TRANSFORMING POWER DEVELOPMENT PLANNING IN THE GREATER MEKONG SUBREGION

A STRATEGIC AND INTEGRATED APPROACH

DECEMBER 2020

ASIAN DEVELOPMENT BANK

TRANSFORMING POWER DEVELOPMENT PLANNING IN THE GREATER MEKONG SUBREGION

A STRATEGIC AND INTEGRATED APPROACH

DECEMBER 2020

ASIAN DEVELOPMENT BANK

6 ADB Avenue, Mandaluyong City, 1550 Metro Manila, Philippines
Tel +63 2 8632 4444; Fax +63 2 8636 2444
www.adb.org

ISBN 978-92-9262-392-0 (print); 978-92-9262-393-7 (electronic); 978-92-9262-394-4 (ebook)
Publication Stock No. TCS200375
DOI: http://dx.doi.org/10.22617/TCS200375

Note:
In this publication, "$" refers to United States dollars and "VND" to the dong.

Cover design by Claudette Rodrigo.

Contents

Tables and Figures

Tables

Figures

Acknowledgments

This report was carried out under a regional capacity development technical assistance of the Asian Development Bank (ADB) on Integrated Resource Planning with Strategic Environmental Assessment for Sustainable Power Sector Development in the Greater Mekong Subregion (TA 9003-REG), with financing from the Agence Française de Développement.

The project as implemented by the consultancy consortium of Ricardo Energy & Environment in association with Manitoba Hydro International Ltd., RTE International, and the Institute of Energy in Viet Nam. Hyunjung Lee, senior energy economist at the Energy Division (SEEN) of ADB's Southeast Asia Department (SERD), managed the project and supervised the study. The reviewers of this report were Anthony Robert Gill, senior regional cooperation specialist at the Regional Cooperation and Operations Division (SERC); Pinsuda Alexander, economist, SERC; Vongphet Soukhavongsa, safeguards officer at the Lao People's Democratic Republic Resident Mission (LRM); Eric Sidgwick, country director, Viet Nam (retired), and Yasushi Negishi, country director, LRM (retired).

The study team consisted of Don Webster (Ricardo Energy & Environment - retired), Pascal Bertolini (RTE International), Andrea Marroni (MRC Group), Nikolay Nikolov, (Ricardo Energy & Environment), Morten Søndergaard (Danish Energy Management), John Soussan (Manitoba Hydro International), and Timothy Wyatt (Power & Water Systems Consultants). Jonathan Hedgecock, Timothy Fill, and Thomas Amram (Ricardo Energy & Environment) provided editorial support.

ADB staff from SEEN Bui Duy Thanh, Carmen M. Ricerra (retired), Minnie Zarah M. Ramas, and Diane Marie B. Carabeo ensured the smooth administrative implementation of the project.

Andrew Jeffries, former SEEN director and current Viet Nam country director; F. Cleo Kawawaki, deputy director general, SERD; and Ramesh Subramanian, director general, SERD, provided invaluable overall guidance and support throughout the project.

Many people made suggestions, provided information, and helped with developing the study. These include more than 250 participants at the study's regional and national consultation meetings, attendees at four Regional Power Trade Coordination Committee (RPTCC) meetings, and those who commented on the various reports. The focal points of the RPTCC were instrumental in providing feedback at the country level, namely, Gnhoung Choumnit and Jona Victor (Cambodia); Somsanith Sadettan, Chitpanya Phamisith, and Santisouk Phimphachanh (Lao's People Democratic Republic);

Mi Mi Khaing, Saw Si Thu Hlaing, and Thein Thura (Myanmar); Wu Ye, Lei Xiaomeng, and Yuan Li (People's Republic of China); and Pham Quang Huy, Le Van Dung, Nguyen Quang Minh, and Do Hung Manh (Viet Nam).

Finally, the support of Arnaud Dubrac of Agence Française de Développement is gratefully acknowledged.

The Publishing Team of Department of Communications including Duncan Mcleod, Cynthia Hidalgo, Noren Jose, Rodel Bautista, and Ma. Katrina Fernando as well as the Printing Services Unit of the Office of Administrative Services of ADB supported publishing and printing of this report.

Abbreviations

AEDP	Alternative Energy Development Plan (Thailand)
BAU	business-as-usual
CCGT	combined-cycle gas turbine
CO_2	carbon dioxide
DEPP	Department of Electric Power Planning
DSM	demand-side management
EDL	Electricite Du Laos
EEDP	Energy Efficiency Development Plan (Thailand)
EE&C	energy efficiency and conservation
EGAT	Electricity Generating Authority of Thailand
EIA	environmental impact assessment
EPPEI	Electricity Power Planning and Engineering Institute (PRC)
EVN	Electricity of Viet Nam
FIT	feed-in tariff
GDP	gross domestic product
GHG	greenhouse gas
GMS	Greater Mekong Subregion
HC	hydrological condition
HVDC	high voltage direct current
ICEM	International Centre for Environmental Management
IFC	International Finance Corporation
IFI	international financing institution
IPP	independent power producer
IRP	integrated resource plan (or planning)
JICA	Japanese International Cooperation Agency
LCOE	levelized cost of energy
LEP	Law on Environmental Protection (Viet Nam)
LMB	Lower Mekong Basin
LNG	liquefied natural gas
M&E	monitoring and evaluation
MCA	multicriteria analysis

continued on next page

MILP	mixed-integer linear programming
MOEE	Ministry of Electricity and Energy (Myanmar)
MOIT	Ministry of Industry and Trade (Viet Nam)
MONRE	Ministry of Natural Resources and Environment (Lao PDR)
MONREC	Ministry of Natural Resources and Environmental Conservation (Myanmar)
MRC	Mekong River Commission
NDC	nationally determined contribution
NDRC	National Development and Reform Commission (PRC)
NEA	National Energy Administration (PRC)
NGO	nongovernmental organization
NOx	nitrogen oxide
PDP	power development plan
PEIA	plan environment impact assessment
PPA	power purchase agreement
PRC	People's Republic of China
RES	renewable energy sources
RPTCC	GMS Regional Power Trade Coordination Committee
SEA	strategic environmental assessment
SEDP	Socio-Economic Development Plan (Viet Nam)
SO_2	sulfur dioxide
SOx	oxides of sulfur
SPP	small power producer
T&D	transmission and distribution
TA	technical assistance
UK	United Kingdom
US	United States
VRE	variable renewable energy
WASP	Wien Automatic System Planning
WEM	wholesale electricity market

Weights and Measures

GW	—	gigawatt
GWh	—	gigawatt-hour
kV	—	kilovolt
kW	—	kilowatt
kWh	—	kilowatt-hour
MW	—	megawatt
t	—	metric ton
tCO_2e	—	metric ton of carbon dioxide equivalent

Executive Summary

Introduction

This report is the second knowledge product produced under regional technical assistance (TA) 9003: Integrated Resource Planning with Strategic Environmental Assessment in the Greater Mekong Subregion. It demonstrates and aims to guide how the preparation of a country's power development plan (PDP) can be transformed—enhancing sustainability outcomes—through integrating strategic environmental assessment (SEA) into an integrated resource planning (IRP) approach. According to the Organisation for Economic Co-operation and Development, SEA refers to a range of analytical and participatory approaches that aim to integrate environmental considerations into policies, plans, and programs, and evaluate how they link to economic and social considerations. Compared to the traditional least-cost planning that considers only limited supply options, IRP can achieve lower overall costs, more fuel savings, and minimize environmental and social impacts.

TA 9003 has provided country-specific technical guidelines to the Greater Mekong Subregion (GMS) counterparts in separate documents, and the rationale behind this document is to consolidate the knowledge gained under TA 9003 into a knowledge product aimed at practitioners in the GMS countries, other Asian countries, and beyond. The GMS includes Cambodia, the Lao People's Democratic Republic (Lao PDR), Myanmar, Thailand, Viet Nam, and Yunnan Province and Guangxi Zhuang Autonomous Region of the People's Republic of China.

Whilst Viet Nam is a leader in the application of SEA in the power sector, the People's Republic of China (the PRC) and Thailand have followed practices like those adopted by Viet Nam, but without a formal SEA structure. In recent years, Cambodia, the Lao PDR, Myanmar, and Thailand have shown considerable interest in integrating SEA in the PDP preparation process. This document provides policy makers with evidence to support the case for such integration.

For decades, the scope of PDPs across the world was limited to the selection of the next large-scale power generation projects to be developed among a restricted range of candidate options. The main objective was to ensure that power generation would continue to balance demand while minimizing costs recoverable from end users.

Successive oil shocks and increasing awareness of the importance of climate change mitigation have forced governments and utilities to rethink their approach to PDP and consider a much broader scope. This includes, but is not limited to, a wider range of power generation technologies including cleaner alternatives, demand-side considerations such as energy efficiency and demand-side management, decentralized as well as centralized power generation options, and cross-border trading opportunities.

The objectives of PDPs—now also often referred to as IRPs—have also shifted from strictly minimizing the cost of service (in financial terms) to maximizing the economic benefits yielded through the implementation of the selected PDP scenario. This typically involves looking at the overall economic cost of providing electricity to consumers from a more holistic perspective. The economic analysis of costs differs from financial analysis approaches in that it also aims to monetize internal and external social and environmental impacts of projects. Such an integrated process puts an ever-increasing emphasis on the importance of integrating SEA within PDPs.

SEA is a concept that has existed since around 2000 but continues to gain traction in the power sector. ADB has been promoting the integration of SEAs into the preparation of PDPs in the GMS since around 2005. Viet Nam has been a pioneer—globally and not solely within the GMS—in integrating SEAs with PDP preparation since around 2005.

An SEA is a process of evidence-based analysis of social and environmental issues within the context of strategic planning. The basic concepts of an SEA include:

(i) balanced analysis to build consensus, including recognizing trade-offs and linking sector goals to national development;

(ii) participation of all interested and affected stakeholders in key stages of the SEA;

(iii) unbiased and objective analysis, with no pre-conceptions over what are desirable outcomes;

(iv) legal status for the SEA—it is now a legal requirement in many countries, including across the GMS, to undertake an SEA for particular types of plans; and

(v) full integration of an SEA into the strategic planning process, rather than being separate from it.

ADB has been in the vanguard of supporting its developing member countries in applying SEAs to the preparation of PDPs. Moreover, it did this in the GMS, where it was actively supporting regional energy cooperation, and where the Mekong River basin is the commonality between the six GMS nations.

Benefits of Integrated Resource Planning

There are significant benefits for countries in implementing a more integrated approach toward resource and power planning, encompassing both technical, economic, financial, environmental, and social considerations. Some of the key benefits are covered in subsections that follow.

Benefits of Including an SEA in the Preparation of PDP

Including an SEA in the preparation of a power plan or program is not undertaken solely for environmental protection; if done correctly it can improve the whole planning process. For example, the SEA is a means to have wider stakeholder involvement and thus build a constituency of support for the plan. Also, the analysis of impacts provides a fuller picture of the implications of different power options. Assigning economic values to these impacts—i.e., internalizing the externalities—facilitates a quantitative assessment of options to provide the mix that is optimal for a country's future development.

An SEA is a means for ensuring that wider national development priorities, such as green growth and climate change mitigation, are integrated into the plan's preparation. Also, an SEA can speed up the whole development process by identifying individual investments that are likely to have serious social and environmental impacts—which can cause delays and controversy. By doing this early in the planning process, such projects can be eliminated from future consideration. An SEA also enables the cumulative impacts of several developments to be assessed, unlike project-level environmental impact assessments (EIAs).

Benefits of Considering a Wide Range of Supply and Demand Side Options

Planners in the GMS and elsewhere tend to favor the technologies they have the greatest familiarity with and concentrate solely on ever-larger projects. Unfortunately, this mindset has precluded consideration of relatively small units in the plant mix. Until quite recently, this meant that technologies such as grid-scale solar or wind farms were not on a utility's radar, and there was even less consideration for micro-scale options such as rooftop solar—despite increasing cost-competitiveness with conventional power generation technologies. In some liberalized regulatory jurisdictions, companies rooted in legacy technologies such as coal and gas have been, and continue to be, outcompeted by market entrants based on renewable energy technologies. Customers are effectively paying the price for dependence on the legacy technologies, and foregoing the benefits afforded by the new technologies.

In the GMS and many countries elsewhere, electricity prices are generally below cost-recovery levels. It is reasonable to assume that further above-inflation tariff increases will occur. The financial sustainability of power utilities is not necessarily incompatible with that of businesses that are likely to face the increase in electricity prices, providing that the system demand is managed in the most energy-efficient way possible. It is widely accepted that having a policy to promote energy efficiency and integrate energy efficiency considerations within PDPs is probably the most cost-effective option for managing energy demand. Developing and implementing a broad range of energy efficiency and conservation (EE&C) initiatives is widely considered to be the best way to surmount the negative impacts of energy production and consumption from various perspectives, including reliability, technical acceptability, affordability, and environmental sustainability (Norzalina Zainudin et al. 2016) .

Benefits of Considering Cross-Border Trading

Cross-border interconnections provide a range of direct and indirect costs and benefits for the parties on either side of the border. A principal direct economic benefit of an interconnection—to the recipient system—is the avoided costs that it delivers. These are direct life cycle costs avoided by receiving power through the interconnection, rather than by generating and distributing that energy through domestic facilities. For the sender, there is a direct economic and financial benefit from the sale of energy to the recipient. Indirect benefits of interconnections may include (i) employment creation for construction and operation; (ii) improved power supplies, either to new or existing customers (as would apply to a new, domestic generation project); or (iii) reduced tariffs to end users.

Developing a fully functioning and interconnected transmission network in all countries of the GMS will be crucial for maintaining the security of the energy supply, for increasing regional power trade, and for ensuring that all consumers can purchase energy at affordable prices. Reducing the number of synchronous areas by synchronizing them is perhaps the cheapest and easiest way to build such a strong interconnected transmission network within the GMS. However, since technical and operational challenges arise in exceptionally large synchronous areas, interconnecting countries through high voltage direct current (HVDC) systems could be easier from an operational perspective, albeit with higher investment costs.

Benefits of Expanding the Cost–Benefit Analysis to Economic Considerations

PDPs relying on economic analysis principles can consider external effects that affect the national economy as well as capital investment and operational expenditure costs. Examples of externalities considered in PDPs include loss of land, impacts on the environmental quality of water and air, the effects of toxic waste, the social impact of resettling populations, etc. Incorporating such considerations in a PDP enables further consistency and harmonization between PDPs and other national plans (e.g. nationally determined contribution [NDC] commitments, oil and gas plans, EE&C plans, renewable energy plans, rural electrification plans, etc.). This, in turn, complements the coherence and efficiency of governmental and interministerial action both nationally and in the provinces.

Current Practices in GMS

Capacity in PDP Development

Although good practice in PDP preparation has advanced appreciably in recent years, many countries— including some of the GMS countries—still follow practices that are closer to the traditional least-cost approach than to IRP best practice. There is a general trend in the GMS countries toward good practice in IRP preparation, although in one or two countries the rate of progress is quite slow. Cambodia, the Lao PDR, and Myanmar do not have the adequate indigenous capability in PDP preparation, and each of these countries has, for many years, been dependent on international consulting firms for the preparation of their PDPs.

It is generally the case that the terms of reference for these PDP preparation assignments have changed little and have not kept pace with trends in the power industry. In some of these countries, the Japan International Cooperation Agency (JICA) is supporting the development of indigenous capacity in preparing PDPs, and in disciplines such as renewable energy and energy efficiency. TA 9003 is facilitating a degree of capacity building through a twinning program. However, it will be some time before Cambodia, the Lao PDR, and Myanmar can prepare PDPs using solely indigenous capacity, whereas the PRC, Thailand, and Viet Nam have had the required capacity for many years. Outside TA 9003, the PRC and Thailand have already been providing capacity-building support in aspects of PDP preparation to other GMS countries.

Although Viet Nam has been preparing IRPs with SEA since around 2005, it acknowledges the need for improvements in some areas. One such area is to adopt more powerful and more flexible generation optimization software.

The Electricity Generating Authority of Thailand (EGAT) is responsible for preparing the PDP for Thailand. EGAT has staff with high levels of technical capability, and the clear integration of related plans for energy efficiency, renewable energy, oil and gas, etc., into the PDP reflects this. However, there are some less remarkable aspects of the process, such as the limited collaboration with other agencies that have a stake in the power sector.

Integration of SEA in PDPs

Vietnam's revised National Power Development Plan VII (RPDP VII) successfully integrated SEA into its PDP—which made a significant impact. RPDP VII can now be a benchmark for SEA integration regionally and internationally. SEAs successfully applied to the hydropower subsectors in countries such as Myanmar, Nepal, Viet Nam, etc., also demonstrate the potential impact of SEAs on power planning.

There are clear indications that movement toward good practice in IRP with SEA will be seen in the future. In Cambodia, the Lao PDR, and Myanmar—where capacity in PDP preparation is limited—there are influential advocates for SEAs in the power sector who are also directly responsible for environmental protection. The pace of change in these countries is therefore likely to be rather modest, albeit in a progressive direction.

Integration of Renewable Energy and Energy Efficiency Considerations in PDPs

Many GMS countries including Myanmar, Thailand, and Viet Nam have implemented frameworks enabling the acceleration of renewable energy development. Many of them are now actively transitioning to higher penetration of renewable energy in their energy mix with a broad range of renewable energy auction processes being carried out across the region.

Although significant potential for improving energy efficiency exists in the GMS, attempts to exploit this potential often fall short because of inadequate national policy frameworks or lack of enforcement of appropriate legislation. Among the drawbacks are (i) policies that artificially lower energy prices—which encourages wasteful consumption; (ii) production and consumption subsidies that distort markets; (iii) poorly managed housing stock; and (iv) barriers to entry for new market participants.

Planning for Cross-Border Trading

While all the GMS countries have international transmission interconnections with one or more of their neighbors, cross-border trade is almost entirely limited to projects developed for export purposes. The current PDP approach—developed on a national basis—is an obstacle to the development of cross-border interconnection, whereas a more regional approach would be more beneficial.

Best Practices

Lessons learned from experience in GMS countries and internationally enable the identification of a set of principles for PDP development.

Key Principle #1: PDPs preparation should follow systemic integrated processes (including SEAs). Although there is considerable variation in the elements of what is considered to be an ideal IRP that are adopted by individual agencies around the world, the steps involved in an ideal IRP are reasonably well accepted in the power industry and in academic circles. Divergence from the ideal is usually taken for rational reasons related to local circumstances. Figure 1 provides a process flowchart for a typical IRP that follows good practice in the industry. The flowchart indicates those activities that are of particular importance when the IRP preparation is integrated with an SEA process. The feedback loops in the process are also of great importance.

Key Principle #2: PDPs should use multicriteria analysis. Objectives for the power planning process are typically described in qualitative terms, whereas quantitative criteria are used to measure the situation with each objective. National development objectives and management strategies, in addition to any subnational objectives, need to be captured in the IRP preparation process. These can typically include minimizing the cost of electricity to end users, but also service reliability, economic cost minimization, diversity of supply, electrification rate, environmental impacts, etc.

Key Principle #3: Enabling frameworks for renewable energy and energy efficiency should be designed and implemented, and PDPs should integrate consideration for renewable energy and energy efficiency. The key technical themes in PDPs should include renewable energy and energy efficiency. Each country is different and there is no single critical success factor that can be applied to guarantee successful renewable energy target setting. Instead, there are three main categories of factors that must be considered:

(i) the policy process—which starts with a political decision on renewable energy targets;

(ii) contextual factors, e.g., geographical and physical factors, socioeconomic factors; and

(iii) energy sector-related factors.

Realizing the opportunities presented by power generation from renewable energy sources (RES) is one of the key challenges facing the power sector in most countries, including those in the GMS. An effective policy and regulatory framework is required that covers factors such as (i) economic, tax, industrial or labor policies; (ii) environmental measures; (iii) education and skills development strategies; and (iv) instruments to facilitate access to finance or conducive institutional arrangements. Importantly, all these measures need to be well coordinated and working.

To facilitate variable renewable energy (VRE), it is essential to ensure that transmission networks are sufficiently robust. However, the International Energy Agency considers that if the share of variable renewables in the total generation mix is less than approximately 10%, there is limited need for significant network modifications to maintain system stability.

An emerging trend for the screening of renewable energy options in PDPs consists of allocating the lowest possible subsidy for an energy or capacity product using a competitive and open bidding procedure. It ensures least-cost development as it provides a vehicle for tendering projects transparently, therefore building investor confidence in the system.

Energy efficiency fiscal policies should be established to incentivize businesses and homeowners to improve energy performance by increasing access to affordable financing for energy efficiency improvements and, ultimately, providing the overall business-enabling environment for improving energy efficiency.

Institutional capacity for developing and implementing national policies on energy efficiency needs to be strengthened, which requires efforts to improve legislation, regulation, and standardization, and other policy and institutional measures.

Key Principle #4: PDPs should facilitate and promote cross-border trade and wheeling, and integrate consideration for cross-border supply options. Evidence from Africa, Europe, and North America shows that cross-border trade can work in the best interests of all parties in terms of (i) shared reserve capacity; (ii) shared ancillary services; and (iii) diurnal, weekly, or seasonal trade between countries with divergent energy resources, e.g., abundant natural gas in one country and abundant but seasonal hydropower in the neighboring country. For example, the Southern Africa Power Pool was established in 1995 and subsequent market development has been quite rapid.

Facilitating cross-border trade and wheeling requires PDPs to consider and mitigate a broad range of issues covering technical, legal, regulatory, and environmental aspects. By failing to consider cross-border electricity trade opportunities in PDPs, including the sharing of reserve capacity and ancillary services, governments—and ultimately consumers—face the additional cost of developing more expensive domestic power generation options.

It is increasingly common for the grid in one country to be the intermediary for cross-border trade between two—or more—other countries. The intermediary is said to be wheeling power and, in return for the use of its transmission network, the utility wheeling the power receives a wheeling charge. Where the trading is through a regional power pool, wheeling charges are typically predetermined and administered by the power pool.

Key Principle #5: External costs should be monetized wherever possible and considered in quantitative analysis. External costs that affect the national economy, but which are not captured in market transactions, should be included. However, many of these externalities are difficult to monetize, and—for some—the scale of the monetized values do not warrant the time and effort required to estimate them. The challenge for planners is to develop an understanding of which externalities have the potential to influence the outcome of the analysis and to focus efforts on determining robustly defensible values for these.

Key Principle #6: Relevant stakeholders should be consulted throughout the process. Globally, there has been increasing recognition over the past 2 or 3 decades regarding the merits of consulting with stakeholders on major plans and projects. Consultation is part of citizen empowerment, which itself is a key element of democracy and good governance. Good governance focuses on governments meeting the needs of all their citizens and not solely select groups in society. Good governance has served to introduce legal frameworks facilitating consultation and enabling nongovernment organizations (NGOs) to champion causes such as sustainable development, the rights of minorities, etc. Legal challenges to major generation and transmission projects are not uncommon in some GMS countries, often resulting in significant delays to implementation. Thorough consultation processes can help avoid these legal challenges and delays.

1 Introduction

1.1 Purpose and Rationale

This report aims to guide how the preparation of a country's power development plan (PDP) can be transformed—providing enhanced sustainability—through integrating strategic environmental assessment (SEA) into an integrated resource planning (IRP) approach. TA 9003 is providing country-specific technical guidelines to the Greater Mekong Subregion (GMS) counterparts in separate documents. The rationale behind this document is to consolidate the knowledge gained under TA 9003 into a knowledge product aimed at practitioners in the GMS countries, other Asian countries, and beyond.

SEA is a concept that is steadily gaining traction. In the GMS countries, the application of SEAs in the power sector was initially quite gradual. The application of SEAs in the power sector in Viet Nam extends back to around 2005, when the Law on Environmental Protection (LEP) required all strategic plans, including PDPs, to incorporate an SEA as part of their preparation. Subsequently, Viet Nam has developed its policies, institutions, and processes to the extent that it is now an excellent model for other countries in the GMS—while it acknowledges that there remains scope for improvement. The extended experience with SEAs in Viet Nam in the power sector is such that a separate knowledge product has been prepared, tracing the evolution of the process of integrating an SEA into strategic planning—either by sector or nationally—from having no experience with SEA integration to having the SEA fully integrated into the PDP process.[1]

As the issues and constraints relating to PDP preparation have become increasingly complex, Viet Nam has found that the inclusion of the SEA has provided a better understanding of the implications of the different development options in the PDP, resulting in significant changes to the final contents of the plan and ensuring alignment of the PDP with the overall national development policies of the country.

Of the other GMS countries, the PRC and Thailand have followed practices with some similarities to those adopted by Viet Nam, but without a formal SEA structure. In very recent years, Cambodia, the Lao PDR, Myanmar, and Thailand are showing considerable interest in integrating SEA into the PDP preparation process. This document provides policy makers with the evidence to support the case for such integration.

[1] ADB. 2018. *Integrating Strategic Environmental Assessment into Power Development Planning in Viet Nam.* Manila.

As outlined in this document, there has perhaps never been a time when there was a more apposite case for the introduction of SEA to PDP preparation.

1.2 Dynamics of Change in Global Power Generation

All the GMS countries are experiencing strong and sustained economic growth. Globalization has resulted in a marked shift in industrial production from developed to developing economies. The rapid increase of demand for electricity by industry, together with strong residential growth, is requiring major expansion of the power systems in the GMS countries. The PDPs in these countries typically include significant capacity additions from thermal generation sources, and particularly from coal-fired power stations. This is a cause of consternation to the international community seeking to mitigate the risk of climate change and global warming due to greenhouse gas (GHG) emissions.

In recognition of the need to act on global warming and climate change, the United Nations Framework Convention on Climate Change (UNFCCC) Conference of Parties (COP) has been meeting annually since 1995. There have been many breakthroughs made since these meetings began, three of which have particular impact on the profile of climate change in power development planning:

(i) At COP 19, held in Warsaw, Poland in 2013, UNFCCC created a mechanism for intended nationally determined contributions (NDCs), which were to be submitted 2 years in advance of COP 21. All the GMS countries prepared and submitted contributions—typically with both unconditional commitments and alternative commitments that were conditional on support from the donor agencies.

(ii) The Paris Agreement, arising from COP 21 in 2015, aimed at limiting global warming to less than 2°C, and to pursue efforts to limit the rise to 1.5°C.

(iii) COP 24, in 2018, agreed on rules on implementing the 2015 Paris Agreement. However, although this agreement aimed at limiting global warming to 2°C, concerns were raised that even limiting global warming to 1.5°C would still have severe consequences for billions of people around the world.

The inference is that the intended NDC commitments may need to be tightened soon.

In addition to worries over thermal generation in the region, the fact that all the GMS countries have plans to develop and/or import from large hydropower projects in the Mekong basin has caused concern about the adverse social and environmental impacts of these projects. These concerns include the significant diminution of fisheries in the lower reaches of the Mekong basin due to the retention of fertile silts in the proposed hydropower reservoirs.

The concern that GMS country PDPs focus on large thermal and hydropower projects is compounded by the fact that these plans are broadly inconsistent with major international trends in the power industry. There are examples of these trends:

(i) GMS country PDPs typically contain negligible to modest renewable energy capacity, such as wind and solar.[2] This runs counter to the international trend in the industry wherein generating capacity from renewable energy sources (RES) is outstripping that from non-RES technologies due to the sustained reduction in the cost of RES capacity—notably solar and wind. There is evidence of this trend:
   (a) In 2016, capacity additions from conventional technologies was approximately 212,000 megawatts (MW), whereas that from RES was approximately 163,000 MW.
   (b) Between 2010 and 2017, the weighted-average levelized cost of energy (LCOE) fell by 73% for utility-scale photovoltaics, 23% for onshore wind, and 33% for concentrated solar power.
   (c) Between 2010 and 2017, the total installed cost of photovoltaics fell precipitously from $4,394/kilowatt (kW) to $1,388/kW, the capacity factor of photovoltaics installations rose from 0.14 to 0.18, and the LCOE fell from $0.36/kilowatt-hour (kWh) to $0.10/kWh.
   (d) Between 1983 and 2017, the LCOE of onshore wind declined by 85%. In the 10 years to 2017, costs declined by around 50% on average.

(ii) With the notable exception of the PRC, Thailand, and—to a lesser extent—Viet Nam, the GMS countries underperform compared to many developed industrialized and developing countries in terms of including energy efficiency initiatives in their PDPs. In some GMS countries, the energy efficiency ambitions are relatively modest and in some others they are non-existent. Thailand's Energy Efficiency Development Plan (EEDP) (2011–2030) aims to reduce energy intensity by 25% in 2030, equivalent to a reduction of final energy consumption by 20% in 2030.[3] The EEDP will result in cumulative energy savings at an average of 14,500 metric tons (t) of oil equivalent per year, $8.5 billion/year, and cumulative carbon dioxide (CO_2) emission reductions at an average of 49 million t/year. Thailand has been setting an example of energy efficiency in the GMS since 1995, and the EEDP is an integral component of the country's PDP.

(iii) While all the GMS countries have international transmission interconnections with one or more of their neighbors, cross-border trade is almost entirely limited to projects developed for export purposes. Although the Regional Power Trade Coordination Committee (RPTCC) has been meeting every 6 months since 2004, progress toward establishing a regional electricity market has been extremely slow. There is, therefore, a high potential for more

[2] Recent PDP scenarios suggest penetration of renewables (excluding large scale hydropower) of less than 15% in the GMS countries.
See ADB. 2015. How Strategic Environmental Assessment Can Influence Power Development Plans: Comparing Alternative Energy Scenarios for Power Planning in the Greater Mekong Subregion. Manila.

[3] Government of Thailand, Ministry of Energy. 2011. *20-Year Energy Efficiency Development Plan (2011–2030)*. Bangkok.

ambitious cross-border arrangements. These are illustrated by experiences in Africa,[4] Europe, and North America, and in a recent study of potential power trade in the Association of Southeast Asian Nations (ASEAN)[5] that cross-border trade can work in the best interests of all parties in terms of (i) shared reserve capacity; (ii) shared ancillary services; and (iii) diurnal, weekly or seasonal trade between countries with divergent energy resources, e.g., abundant natural gas in one country and abundant but seasonal hydropower in the neighboring country.

(iv) Solar photovoltaics are a distinctly intermittent RES that the combination with energy storage solutions helps mitigate, in particular, where photovoltaics supplies off-grid networks or where the transmission system is very weak. In the same way that economies of scale have played a major role in driving down the LCOE of photovoltaics—which helps fuel demand for this solar panels, this explosion in the use of photovoltaics is also fueling demand for battery storage to be used with photovoltaics, and scale-effects are driving down battery costs. Also—in response to the necessity to reduce GHG emissions—lawmakers and regulators are promoting the development of hybrid or battery-powered electric vehicles, with the result that battery costs are falling, to the benefit of both the electric vehicle and energy storage markets. Generally, the PDPs of most GMS countries do not account for battery storage.[6]

Other notable global trends are not yet prominent in the GMS countries. Where the regulatory regime permits, utilities rooted in conventional technologies such as coal and gas are often being outmaneuvered by start-up companies that have harnessed disruptive technologies (e.g., solar photovoltaics and solar photovoltaics plus storage) with innovative financing mechanisms. In some instances, these market entrants are consolidating the management of rooftop solar, home battery systems, electric vehicle charging, etc., forming virtual microgrids within existing grids, and using software technologies—such as blockchain—to outcompete the incumbent utilities. Regulatory frameworks in GMS countries do not widely facilitate such innovations to operate, although there are exceptions, such as the so-called "Sandbox" initiative being implemented by the Energy Regulatory Commission in Thailand, which encourages the development of technologies such as peer-to-peer electricity trading and projects to develop electric vehicle charging and storage. The lesson is that where they are allowed to operate, such innovations are delivering commercial efficiencies and lower energy costs for end users, especially the public.

The global changes outlined in this report have focused on the challenges facing the international community in addressing climate change and global warming,

4 The Southern Africa Power Pool was established in 1995 and subsequent market development has been quite rapid. More information is available at www.sapp.co.zw/about-sapp.

5 More information on ASEAN experience is detailed by the International Energy Agency. 2019. *Establishing Multilateral Power Trade in ASEAN.* https://asean.org/storage/2020/02/Establishing_Multilateral_Power_Trade_in_ASEAN.pdf.

6 In mitigation, the GMS countries generally have access to hydropower resources which, subject to any multipurpose constraints such as irrigation releases, can often be operated conjunctively with intermittent renewable energy capacity such as wind and solar.

and how the rapid penetration of technologies such as wind and solar energy are increasingly prominent in the fight to limit GHG emissions. However, there is another significant area that warrants mention, and that is the liberalization of electricity markets.

Market liberalization has been gathering pace since it was introduced in Chile and the United Kingdom (UK) during 1985–1989, and largely predates efforts to correct global warming. This change to legal and regulatory frameworks has generally been motivated to promote efficiencies and innovation that leads to lower tariffs and better supply reliability to customers. In the UK, industry restructuring, privatization, and the introduction of a pool for trading wholesale electricity were introduced almost simultaneously, and the introduction of a retail market followed within a few years. An industry model like that of the UK has been adopted by a small minority of countries around the world.

Many countries, including all the GMS countries, have modified industry structures and regulatory frameworks to enable the private sector to finance, build, own, and operate generation facilities that feed into the national grid. The businesses that develop these facilities are known as independent power producers (IPPs). The IPPs tend to be large, conventional thermal projects or large hydropower projects that supply power to a transmission entity and/or single buyer under a contractual arrangement known as a power purchase agreement (PPA)—especially in developing countries. Since IPPs are typically under limited-recourse financing arrangements, the PPA instrument is required by the project's financiers to provide a good degree of assurance that the developer's debt service obligations will be met in full.

Outside a relatively small number of developed countries, it is rare for IPP companies to construct large projects without a PPA, trusting an electricity market to provide adequate revenues—sustained over several years—to meet all the company's costs, including the debt service obligations. Electricity markets are uncommon in developing markets. Viet Nam is set to become the first GMS country to introduce a wholesale electricity market (WEM), which may herald significant market liberalization in the GMS countries. Under the Vietnamese WEM, new IPPs will be required to trade electricity in a spot market, and incumbent market participants will be required to gradually increase their exposure in the spot market.

Experience from a handful of countries such as Australia, Japan, the UK, and the United States (US) demonstrates how the private sector—often start-ups financed by venture capital organizations—can develop relatively small-scale renewable energy capacity that is cost-competitive, and with enough conventional sources of generation that slow moving incumbent generators are being displaced from these markets and becoming a burden. Although unfortunate for these legacy generators, it is advantageous to both the innovators and the end users who benefit from lower electricity prices.

The development and operation of electricity networks also need to be adapted to this new context. A considerable change in the role of network users and network operators will be required to attain the various objectives of augmenting security of supply, creating and/or developing competitive markets, and expediting the transition to a low-carbon economy.[7]

Future network users will increasingly be required to play a proactive role in the delivery of services and functionality required to maintain the security of the transmission system (footnote 7).

In the future, operating conditions under the highest levels of RES injection (typically windy/sunny conditions with moderate demand) present major system challenges—particularly where the high RES penetration extends across a complete national system, or even more if covering a total synchronous area. The move toward a more RES-dominated system implies a gradual diminution of the large-scale generation connected at extra high voltage level, which will be further compounded by this generation having much-reduced running hours compared to current levels. The main solution to this is to increase the controllability and the flexibility of all power system elements, including RES, to deliver a power system that can react and cope better with the variability of RES. The establishment of grid codes— including these new requirements of flexibility and controllability—is a major challenge for GMS countries (footnote 7).

To promote private sector participation in power generation—both grid-connected IPPs and off-grid small power producers (SPPs)—it is important to establish an independent regulator for the electricity sector. An Electricity Authority is becoming an established feature in developing markets that are making significant progress in market liberalization.

Internationally, governments have taken important steps toward their energy efficiency potential. Achieving greater energy efficiency that faces up to the challenge of sustainable social, environmental, and economic development has been a key component of energy policies worldwide. Within the GMS, there are significant variations in energy consumption patterns and sectors of economic activity. The rapid economic growth in the GMS is closely linked to the expansion of the energy sector. The GMS countries have significant potential for improving energy efficiency, and some of the countries have addressed this through the development of energy efficiency activities within the last decade. Frequently, however, efforts to improve energy efficiency are limited due to either national policy frameworks that are inadequate or legislation that is not rigorously enforced. Obstacles include (i) energy prices and/or tariffs set well below cost-recovery levels resulting in excessive consumption, (ii) market distortions due to production and consumption subsidies, and (iii) barriers to entry for new market participants.[8]

7 entsoe. 2012. Network Code "Requirements for Generators" in view of future European electricity system and Third package network codes. https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_RfG/120626_-_NC_RfG_in_view_of_the_future_European_electricity_system_and_the_Third_Package_network_codes.pdf.

8 UNECE. 2015. *Energy Efficiency: getting more from less.* Geneva. https://www.unece.org/fileadmin/DAM/energy/se/pdfs/Booklet_Dec2015/Booklet_Energy.Efficiency_Dec.2015.pdf.

1.3 Integrated Resource Planning with Strategic Environmental Assessments and Sustainable Power Development Plan Development

Failings of Previous Approaches to Power Development Plan Development

A key failing in PDP development internationally is that planners often tend to favor the technologies with which they have the greatest familiarity. This may be attributed to indigenous resources such as coal, gas, or hydropower, or due to a near-total lack of such resources and a dependence on imported fuels such as coal or oil. A country that has successfully developed several large hydropower projects, for example, will typically have developed institutions and skill sets to facilitate the topographical surveying, hydrology, geotechnical investigations, resource modeling, feasibility studies, oversight of financing arrangements, etc., necessary for the development of these projects. In such cases, it is highly likely that the portfolio of candidate projects under consideration will have a preponderance of large hydropower projects that have been identified and studied in the recent past. At the same time, if there are institutions and skill sets that are strong in hydropower development, following this example, it is unlikely that there is also comparable capacity in relation to other technologies, such as wind and solar.

Inertia to diversify the technology mix may not solely be attributable to narrow skill sets either. Where there is a prevalence of a technology, it is not uncommon for a political dimension to enter decision making on candidate projects, and in some instances, vested interests. Political expediency may require that the preservation of employment in coal mining and coal-fired power stations, for example, becomes a planning objective that is broadly inconsistent with sustainability objectives.

In addition to a reluctance to include diverse technologies as candidates for the PDP, planners are often culpable of concentrating solely on ever-larger projects. It is historically correct that as a power system expands it can absorb larger generation units, and that those larger units of a technology are usually more cost-efficient than their smaller cousins due to scale effects. This mindset has precluded consideration of relatively small units in the plant mix in some instances. Until quite recently, grid-scale solar or wind farms were not on a utility's radar, and still less was a consideration of micro-scale options such as rooftop solar. With the increasing cost-effectiveness of renewable energy technologies, most planning agencies in both developed and developing countries have adjusted to the new realities. In some liberalized regulatory jurisdictions, companies rooted in legacy technologies such as coal and gas are being outcompeted by market entrants based on renewable energy technologies, resulting in dire financial consequences for the incumbents. Systems without a liberal market are not affected in the same way; instead, it is customers that are effectively paying the price for dependence on the legacy technologies, and foregoing the benefits afforded by the new technologies.

Until recently, planners were not required to consider the impacts of their generation mix on global warming and climate change. This has changed, with most countries in the international community—including those in the GMS—having made NDC commitments in 2015 on reducing GHG emissions. These commitments have made it difficult for planners to ignore renewable energy technologies. Moreover, it has required new institutions and skillsets to facilitate the development of projects based on renewable energy. Most GMS countries are having to rapidly develop the capacity needed to enable the rollout of renewable energy projects.

On the issues of environmental and social sustainability, the NDC commitments help ensure that there are no free riders on GHG emissions—which have global implications.[9] Nevertheless, to limit environmental and social impacts of individual projects, particularly those in the power sector, it is the convention—and usually a legal requirement—for an environmental impact assessment (EIA) to be prepared for each project, and for that EIA to be reviewed and approved by the environmental regulator before the project is licensed to operate. Unfortunately, there are shortcomings to this approach. The problem is not that EIAs are undertaken—and it is unlikely that any advocate of SEAs would suggest this—the issues are that (i) EIAs focus on individual projects rather than programs, and (ii) EIAs are prepared very late in the project development cycle.

With an approach wherein the focus is on a generation technology and ever-larger plant sizes, the development of a project can be several years in the planning. Before financial close on a large hydropower project, for example, there will typically be a series of lengthy and relatively expensive resource, pre-feasibility, and feasibility studies, during which a range of options will be identified and—through these progressive studies—whittled down to the priority project. Coal and gas-fired projects—in addition to their construction periods of 4 or 5 years—often require extensive planning in terms of the sourcing of the fuel, and the development of shipping, handling, transportation, and storage infrastructure.

The EIA comes late in the process, and this is when project-affected people and environmental nongovernment organizations (NGOs) become most vocal—and litigious—in their opposition to the project. If the impacts and mitigation measures are fully costed, including the cost of externalities, the project may not be economically viable. Canceling the project and developing an alternative may set the expansion program back by several years, resulting in high costs for either emergency capacity provision or prolonged periods of reduced service reliability. The momentum that develops behind these projects with long gestation periods renders it tempting for governments—and not just the planners—to proceed with an environmentally and socially harmful project. Generally, governments in the GMS countries have robust safeguarding systems, which often translates to generation or transmission projects being delayed or canceled. As this document

[9] In this instance, a free rider is a country that benefits from minimizing the impacts of global warming, but which does not contribute, or does not contribute commensurately, thus requiring that other countries contribute disproportionately.

will explain, the SEA aims to avoid late-stage social and environmental problems arising on projects. TA 9003 has found that this message is a hard sell in some GMS countries, particularly those that routinely experience delays to projects on social and environmental grounds, with SEAs viewed as yet a further obstacle in the way of timely project implementation.

How IRP with SEA Addresses Unsustainable PDP Approaches

To redress the shortcomings of previous approaches to PDP development, planners need to adopt more rigorous IRP approaches, and, also, SEA principles need to be integrated with the PDP preparation process.

Chapter 2 of this document elaborates the key details of a good practice IRP approach to PDP preparation, the main features of which are as follows:

(i) The IRP is consistent with all the relevant national development policies, strategies, and plans. This includes consistency with NDC commitments; green growth strategies; and—where prepared separately from the PDP—energy efficiency plans, renewable energy plans, rural electrification plans, etc.

(ii) The IRP objectives and criteria are clearly defined at the outset, subjected to stakeholder scrutiny and consensus, and consider the findings of the body tasked with monitoring and evaluating previous PDPs to identify lessons to be learned.

(iii) The IRP follows an iterative process, since the demand forecast underpinning the plan is premised on tariff assumptions, while a cost-recovery tariff cannot be determined until all the internal and external costs have been evaluated and used to determine the least-cost expansion program.

(iv) Before initial screening of the supply and demand options can be undertaken, extensive data collection is required across all technical, economic, environmental, and social aspects of these options.

(v) The IRP identifies supply options, transmission, and distribution requirements, import options and related prices, and also demand-side options; each of these to be subjected to social and environmental assessment using the collected data.

(vi) Taking account of stakeholder consultations and the findings of the monitoring and evaluation (M&E) body, the IRP undertakes a preliminary assessment of the supply-side and demand-side options that successfully passed the social and environmental screening in the previous step. It should be noted that under the iterative approach, marginal costs may need to be adjusted for each iteration.

(vii) Based on the preliminary assessments, supply-side and demand-side plans are developed to meet the demand forecast.

(viii) From these supply-side and demand-side plans, candidate IRPs are developed, assessed, and subjected to risk analysis and scenario analysis. These assessments will take full account of the impacts and costs determined during the earlier social and environmental assessments.

(ix) The output from the IRP assessments will then be subjected to management review, with this review taking full account of stakeholder consultations.

(x) Management will determine the preferred and contingent IRPs, prepare an implementation plan, and begin the implementation of the preferred IRP.

(xi) The M&E body will monitor the implementation process—and related factors and influences—and advise management if the necessity to consider a shift to a contingent IRP arises, e.g., due to significant changes in demand or fuel prices.

An overarching feature of a good practice IRP, from recent experience, is that it is neither possible nor desirable to enter all the quantitative data into a software model and to adopt the output as the definitive PDP. One of the key reasons for considering a range of candidate IRPs in 2020 is because of the increased complexity and multiple facets of modern power systems. Whereas it was once sufficient to set the objective of an IRP as producing the least-cost combination of generation and transmission investments to deliver electricity at an optimum level of reliability, this is no longer sufficient. Objectives today are numerous, wide-ranging, and, in some instances, conflicting. Typical objectives may include service reliability, cost minimization, robustness, flexibility, diversity of supply, energy security, electrification rate, reduced end user tariffs, welfare benefits, environmental impacts, use of local resources, and technology acquisition.

Stakeholders have differing priorities, and the task of management is to strike a balance of met objectives. To do so, it is prudent to consider a good range of candidate IRPs. Chapter 2 notes that in preparing their 2013 IRP, PacifiCorp, a utility in the US, applied 19 scenarios across five different transmission scenarios, yielding 94 different variations of resource portfolios.[10] PacifiCorp's resource measures included a diverse range of thermal and nuclear generation; renewables; various dispersed and/or locational generation technologies, including rooftop solar photovoltaics, gas turbines, and various energy storage technologies; and a diverse range of EE&C and demand-side management (DSM) measures.

Some of the GMS countries do not yet prepare PDPs with the rigor of a good practice IRP. To undertake an IRP with an SEA is to take the process to another level. Chapter 2 of this document presents key details of international best practice in SEA. For this introductory chapter, preparing an IRP

---

[10] The Brattle Group. 2014. *Electric Utility Integrated Resource Plan.* Boston. http://files.brattle.com/files/6048_electric_utility_integrated_resource_planning.pdf.

with an SEA entails preparing the SEA contemporaneously with IRP preparation. The SEA aims are to

(i) help achieve environmental protection and sustainable development,

(ii) strengthen and streamline project EIAs, and

(iii) integrate the environment into sector-specific decision making.

The SEA is also an opportunity for wider stakeholder consultation and thus build support for a plan.

A rigorous SEA includes an assessment of potential social and environmental impacts, together with their risks and uncertainties. It then determines the internal (e.g., mitigation requirements) and external (e.g., health impacts of air and/or water pollution) costs associated with these impacts. Assigning costs to social and environmental impacts in the plan requires good data and recognized methodologies.

Contrary to some misconceptions in the industry, an SEA can speed up the whole development process by identifying individual investments that are likely to have serious social and environmental impacts—which can cause delays and controversy. By doing this early in the planning process, such projects can be eliminated from future consideration. It is also a means to understand the cumulative impacts of several developments.

When integrated with an IRP, SEAs should predict the potential impacts (positive and negative) of different planning options and evaluate whether these impacts are significant enough to need actions to mitigate them, reducing the negative ones and enhancing positive ones.

1.4 Scope of This Document

Following this introductory chapter, a further six chapters develop guidance on how the preparation of a country's PDP can be transformed—providing enhanced sustainability—through an SEA into an IRP approach.

Chapter 2 provides an overview of IRP: an approach to PDP preparation designed to provide greater social and environmental sustainability. A definition and explanation of IRP are provided at the outset of the chapter. The chapter then turns to a review of international good practice for IRP in power planning.

Chapter 3 identifies the key technical themes that require consideration in an IRP, notably energy efficiency measures, renewable energy integration, and cross-border interconnection between countries.

Chapter 4 reviews SEAs, commencing with the evolution of SEAs, their application to the power sector, and adoption by the GMS countries. Some of the GMS countries do not yet prepare PDPs with the rigor of a good practice IRP. To undertake an IRP with an SEA is to take the process to another level. The chapter presents key details of international best practice in SEAs, together with the status of SEA policies and practices in the GMS countries. For this introductory chapter, preparing an IRP with an SEA entails preparing the SEA contemporaneously with IRP preparation.

Chapter 5 considers the economic analysis approaches adopted in good practice IRPs to establish lessons for the GMS countries, and addresses the point that IRPs are an exercise in economic analysis; they are prepared from a national perspective using costs and benefits stated in economic terms, and generally adopt economic analysis methodologies recognized by international financing institutions (IFIs) such as ADB. Unfortunately, many of the well-documented IRPs in the public domain are those prepared for utilities in the US and, despite having various merits relevant to this document, are invariably undertaken in financial terms from the perspective of the utility—with great emphasis on tax credits, subsidies, etc., that are not relevant to true economic analysis.

Chapter 6 considers the modeling required for the IRP preparation process. For relatively large power systems such as those in the GMS countries, optimization of the wide range of supply-side and demand-side options available to the planners—subject to a wide range of objectives and constraints—requires a sophisticated software suite incorporating a powerful optimization module. Two of the three GMS countries that prepare PDPs using their own teams of planners and modelers—Thailand and Viet Nam—appear to be close to reaching the limit of the capability of the relatively dated optimization models available to them. TA 9003 has undertaken a set of optimization runs for Viet Nam, using a recently developed software model that uses mixed integer linear programming (MILP)—which is computationally very powerful. The model runs incorporated data sets from Viet Nam's Revised PDP VII. The object of the modeling exercise was to learn lessons with application to the GMS countries on issues specific to IRP modeling. Chapter 6 focuses on the lessons learned from the TA 9003 modeling for Viet Nam. Lastly, potential progression paths for IRP modeling in the GMS countries are proposed.

Chapter 7 contemplates the directions for IRP with SEA in the near future, before postulating how IRP with SEA can be a catalyst for sustainable power sector development. The chapter starts by considering the establishment of policy frameworks required for IRP with SEA. It then reviews the characterization of an IRP with an SEA approach to PDP preparation and provides a summary of the key conclusions from TA 9003. A vision of the transformative advantages of IRP with SEA is presented.

Appendices to the main document provide the following:

(i) a summary of the results of the gap analysis that was carried out for each of the GMS countries, identifying areas where each could make improvements in applying SEA in IRP (Appendix 1);

(ii) an overview of the characteristics of recent SEAs prepared in the GMS (Appendix 2);

(iii) a summary of current practices in the GMS countries relating to an economic analysis of power development plans (Appendix 3);

(iv) a review of IRP modeling approaches adopted by the different countries (Appendix 4); and

(v) capacity-building recommendations for each of the GMS countries, together with a vision of how the countries may transition toward a good standard of IRP with SEA, recognizing that they each have different starting points for this transition process (Appendix 5).

2 Overview of Integrated Resource Planning

2.1 Introduction to Integrated Resource Planning

Background to the Genesis of Integrated Resource Planning

For many decades, the electricity supply industry has been of such immense strategic national interest that governments around the world have controlled power planning to ensure—among other things—adequate supplies of reliable and affordable electricity to end users. Without these, a nation's economic growth and the population's social welfare would be adversely affected—potentially to a serious degree. Globally, PDPs are still prepared by many national or federal governments or their power utilities. Until quite recent decades, PDPs took the form of a very basic form of analysis wherein demand was projected over a planning horizon of 20 to 30 years, and a generation expansion program was developed to meet the demand projections—at least economic cost—to the nation or the federal state.

Typically, least-cost expansion planning only considered a limited range of large-scale generation candidates, such as coal- or gas-fired thermal plants, or large hydropower projects.[11] Such plans rarely involved consideration of EE&C, nor did they usually consider non-hydropower renewables of either large or small scale. External costs—such as those from the adverse health impacts of coal-fired generation— were not taken into consideration in the analysis. The planning process was essentially top-down, and although a degree of interministerial review may have been undertaken, there was generally no consultation with stakeholders beyond the large, state-owned enterprises. A good number of nations still plan power along these traditional lines and, while it may be the case that a balance can be struck between supply and demand, the approach is widely considered to have some critical weaknesses:

(i) By failing to consider demand-side options such as EE&C and DSM initiatives, alongside the supply-side options, the resulting expansion program is unlikely to be least cost to either a nation or end users.

(ii) By failing to consider a wide range of renewable energy generation options, both large or small scale, it becomes less likely that a country would meet its carbon-reduction commitments or, even if it did meet its overall targets, it is unlikely that it would do so at the least cost to the nation. It is also likely that it is failing to benefit from the rapid advances in the cost-competitiveness and other advantages (e.g., environmental

11 The Tellus Institute. 2000. *Best Practices Guide: Integrated Resource Planning for Electricity*. Boston. https://pdf.usaid.gov/pdf_docs/PNACQ960.pdf.

and social) provided by solar and wind energy technologies, especially when applied in tandem with storage technologies that have also experienced rapid decreases in cost in very recent years.

(iii) By failing to consider demand-side options and renewable energy generation options, a government is unlikely to achieve consistency in its national policies which, in addition to international commitments on carbon reduction, may include policies on green growth and sustainable development.

(iv) By failing to consider the cost of externalities such as the social cost of carbon or the health impacts of air and water pollution from thermal generation, and the long-term adverse impacts caused by impounding hydropower plants (e.g., loss of biodiversity, loss of livelihoods, dislocation of communities, etc.), the resulting expansion program is unlikely to be truly least cost to a nation due to the long-term costs directly related to the externalities.

(v) By failing to consider cross-border electricity trade opportunities, including the sharing of reserve capacity and ancillary services, governments—and ultimately consumers—may face the additional cost of developing more expensive domestic power generation options.

(vi) By failing to undertake thorough consultation with all key stakeholders (e.g., end-use consumers, employees in the supply chains, householders living near existing and candidate generating stations, and the public), not only is a government effectively disenfranchising its citizens, but it is also missing opportunities to learn from these groups, e.g., suggestions on more effective EE&C or DSM measures.

The oil price hikes of the 1970s exposed the frailties of basic least-cost expansion planning. The age of cheap energy had ended, and consumers had to reassess their consumption practices and investment decisions. No longer was it either practical or economic to simply choose the least-cost investment plan that met a profile of projected demand that failed to consider demand-side opportunities. The US had enjoyed extremely low energy prices for many decades before the 1970s and therefore the 500% increase in the price of crude oil from 1973 to 1980 had a great impact in that country. Consequently, the US turned to IRP in the 1980s and their preparation has become mandatory in many states of the US.[12]

Reassessment of expansion planning processes in response to higher energy prices coincided with greater concern about the environmental impacts of projects. The scope of IRP was soon expanded to capture social and environmental concerns, and over the years the scope has broadened to capture concepts such as equity, stakeholder consultation, etc. Individual countries have, however, introduced country-specific considerations to suit any national circumstances or priorities.

[12] Thirty-four of the 50 states in the US have mandatory requirements for IRPs.

Although there have been several decades of international experience in preparing PDPs, the evolving situations in economies and electricity sectors in many countries are such that the task is becoming more challenging. Causal factors for the challenging nature of undertaking these studies include the following:

(i) rapid economic growth, urbanization, rising per capita incomes and consumption, and demands for electrification of rural areas;

(ii) constant changes in the cost structure of electricity infrastructure, most notably in the generation subsector, where disruptive technologies such as wind and solar energy, and energy storage have started to become more cost-effective than some conventional generation technologies such as coal-fired steam;[13]

(iii) high volatility in world commodity markets (including oil and gas);

(iv) the information and communication technology (ICT) age has become almost universally pervasive, which heightens the demand for reliable electricity supplies, which—in turn—translates to a high imputed cost of unserved energy demand;

(v) rapidly escalating energy prices and concerns about global warming and climate change have increasingly made it both economically advantageous and politically correct to implement energy efficiency measures that reduce demand, and considerable investment has been made in more energy-efficient technologies;

(vi) increased realization—often promoted by the policies of multilateral agencies—of the merits of cross-border trade in electricity, rather than each country being self-sufficient and insular;

(vii) changes to the financing of power projects, which includes increased reluctance of the development agencies to lend for generation projects, in general, and specifically those using fossil fuels, and recognition that private developers and their financiers are often able to mobilize innovative solutions more expediently than is possible with public funding, particularly where those solutions involve the disruptive technologies;

(viii) heightened sensitivity of both the national and international communities to social and environmental concerns, including global warming and climate change, localized pollution and environmental degradation, displacement of communities, and loss of livelihoods such as in agriculture;

(ix) the social and environmental concerns generally lead toward a requirement for the associated internal (e.g., compensation for displacement) and external (e.g., impacts on climate change) to be considered when preparing the PDP; and

[13] Disruptive technologies are those that significantly alter the way businesses or entire industries operate. Often, these technologies force companies to alter the way they approach their business, or risk losing market share or becoming irrelevant. Recent examples of disruptive technologies include smartphones and e-commerce.

(x) the social and environmental concerns generally add to the case for consultation processes, so that local communities, national and international NGOs, and other stakeholders can review proposals and raise their concerns before the PDP is finalized.

Examples of the Application of IRP

Since IRP was introduced following the oil shocks in the 1970s, numerous countries, states and utilities have adopted it, to a greater or lesser degree, for planning the expansion of their power sector:[14]

(i) IRP was introduced in **the PRC** during 1990–1994, and new DSM regulations came into effect in January 2011.

(ii) **India** applies the IRP approach to produce its Five-Year National Electricity Plan.

(iii) Since the 1990s, Electricity Generating Authority of Thailand (EGAT) has integrated its PDP with DSM plans.

(iv) Most states in the **US** (at least 30) have been using IRP for many years.

(v) **Brazil's** utilities are not obliged to conduct IRP but some follow procedures consistent with IRP.

(vi) In **Chile**, although IRP is not strictly being carried out, several energy efficiency programs are in progress.

(vii) **South Africa** is one of very few countries to legally require IRPs for national electricity.

(viii) Some electricity utilities in **Canada** have been undertaking IRPs for more than 2 decades, and BC Hydro's first IRP was prepared in 1995.

(ix) **Barbados** decided to undertake power IRPs as recently as 2012.

(x) The utility in **Bermuda** is updating a power IRP at the request of the regulatory authority.

---

14 International Energy Initiative. 2011. *Integrated Resource Planning; Part 1: Recent practice for the power sector.* Bangalore. http://iei-asia.org/reports.

It has been observed that the interpretation of IRP varies from country to country, with very few of them undertaking a thoroughly rigorous approach—often for good practical reasons:

(i) Some countries follow the ideal approach, i.e., an evaluation of the economic costs of both supply- and demand-side options, including externalities.

(ii) Some countries, including most states in the US, limit cost considerations to the utility's financial costs and only consider some externalities.

(iii) Agencies in some countries fall even further short of the financial cost approach and stop short of fully integrating renewable energy and DSM and/or energy efficiency options (footnote 14).

Approaches to the costing procedure vary from country to country and include:

(i) Economic costs determined by rigorous analysis, with the monetization of environmental and societal impacts:

This is the ideal approach since it reflects a society that is conscious of both equity and the value of the environment. However, no planning authority attempts to capture all externalities.

(ii) The cost of mitigating or compensating for environmental or societal impacts, in addition to using prices that are inclusive of all charges and taxes:

This approach is subject to prevailing regulations and how society perceives the various impacts. For example, society in the US can be overly sensitive to some impacts.

(iii) Using prices based only on direct payments incurred:

India adopts this approach and charges for water use, polluting discharges, etc. These charges are generally well below the actual economic cost (footnote 14).

Following the establishment in the 1980s of IRP as the gold standard in the sustainable development of power in a particular jurisdiction, a further two trends arose. The first of these—rising to prominence in the UK and Chile during 1985–1989—was the introduction of a role for markets in allocating power resources.[15] The second trend arose in the 1990s when environmental scientists— already concerned about pollution and other adverse impacts of electricity generation arising from rapid global economic growth—became aware of global warming and climate change resulting from GHG emissions. While the trend toward markets equated to a reduced role for centralized planning, international commitments to help solve global warming required government interventions on planning and management of power and energy. As elaborated in the challenges

15 In the GMS countries, Viet Nam has introduced a wholesale electricity market since 2019.

with IRP, these trends required responsible governments to rethink their approaches to power sector expansion planning.[16]

Challenges with IRP

Although this document has noted that IRP has been adopted by some countries both large and small, there are various reasons why many other countries do not adopt it and that countries often adopt a pick-and-mix approach to the aspects of an ideal IRP they embrace and those they disregard. There are many reasons behind the lack of universal adoption of an ideal IRP—or even any form of IRP:

(i) Whereas IRP implicitly involves a high degree of central planning, some countries have adopted a more laissez-faire approach to expansion planning, encouraging private participation in the sector generally, and in generation particularly. The rapid penetration of combined-cycle gas turbine (CCGT) stations in the 1990s, and wind and solar energy projects within the past 10 years, is largely due to deregulation that has facilitated innovation from developers, manufacturers, and financiers, to the general benefit of consumers and national economies. At the same time, countries such as the UK have curbed this approach and reintroduced significant government support to ensure that the generation mix is (a) diversified by the inclusion of replacement nuclear energy, and (b) inclusive of enough renewable energy capacity to meet international commitments on climate change.

(ii) The relatively sudden and seemingly relentless advance of transformational technologies and commercial arrangements (such as wind and solar energy, energy storage, financial engineering, e-commerce) often outpaces central planning agencies, where there is often considerable inertia working against any rapid shift away from traditional technologies and approaches.

(iii) Undertaking the data capture and the modeling needed to produce an ideal IRP that takes full account of renewable energy and energy efficiency opportunities, environmental and other external costs, imports and exports, is beyond most agencies, which are often budget-constrained.

(iv) Some developed countries, and increasingly some developing countries, have wholesale electricity markets, where market participants respond to the pricing signals in those markets. In these markets, technologies, such as coal-fired steam, can be displaced before their productive life expires (i.e., become stranded assets) by disruptive technologies (wind, solar, storage, etc.). IRPs are strictly undertaken consistent with economic principles that take costs extant at the time the analysis is undertaken. It would be incorrect to second guess future prices other than through sensitivity analysis.

16 M. K. Jaccard. 2002. *Energy Planning and Management: Methodologies and Tools.* Encyclopedia of Life Support Systems. Oxford, UK.

Other Approaches to Power Sector Expansion Planning

The IRP of the form outlined in this document is most relevant in a vertically integrated monopoly situation. These still exist in some countries but are becoming increasingly less common. The power sectors in most countries are somewhere further along the reform continuum, with incremental degrees of restructuring and deregulation. This continuum culminates in a highly liberalized, market-led power sector, like the one in the UK. IRP can still be relevant at the various stages but needs to be reinvented as a nation progresses along the continuum.

When a power sector is liberalized, entities in the unregulated market assume a role in the selection of, and investment in, generation facilities. Consequently, due to the diminished role of governmental or regulatory agencies, IRP needs to adapt to the reformed market structure. Where retail competition is introduced, IRPs possess a more indicative status (footnote 11).

Despite the flexible nature of an indicative IRP, critical policy variables can still underpin the performance of the sector—such as end-user tariffs and environmental sustainability—an indicative IRP can assist with monitoring performance in these respects. Consequently, the monitoring process can inform policy development on industry structure and regulation.

2.2 International Good Practice for Integrated Resource Planning in Power Sector Planning

Overview

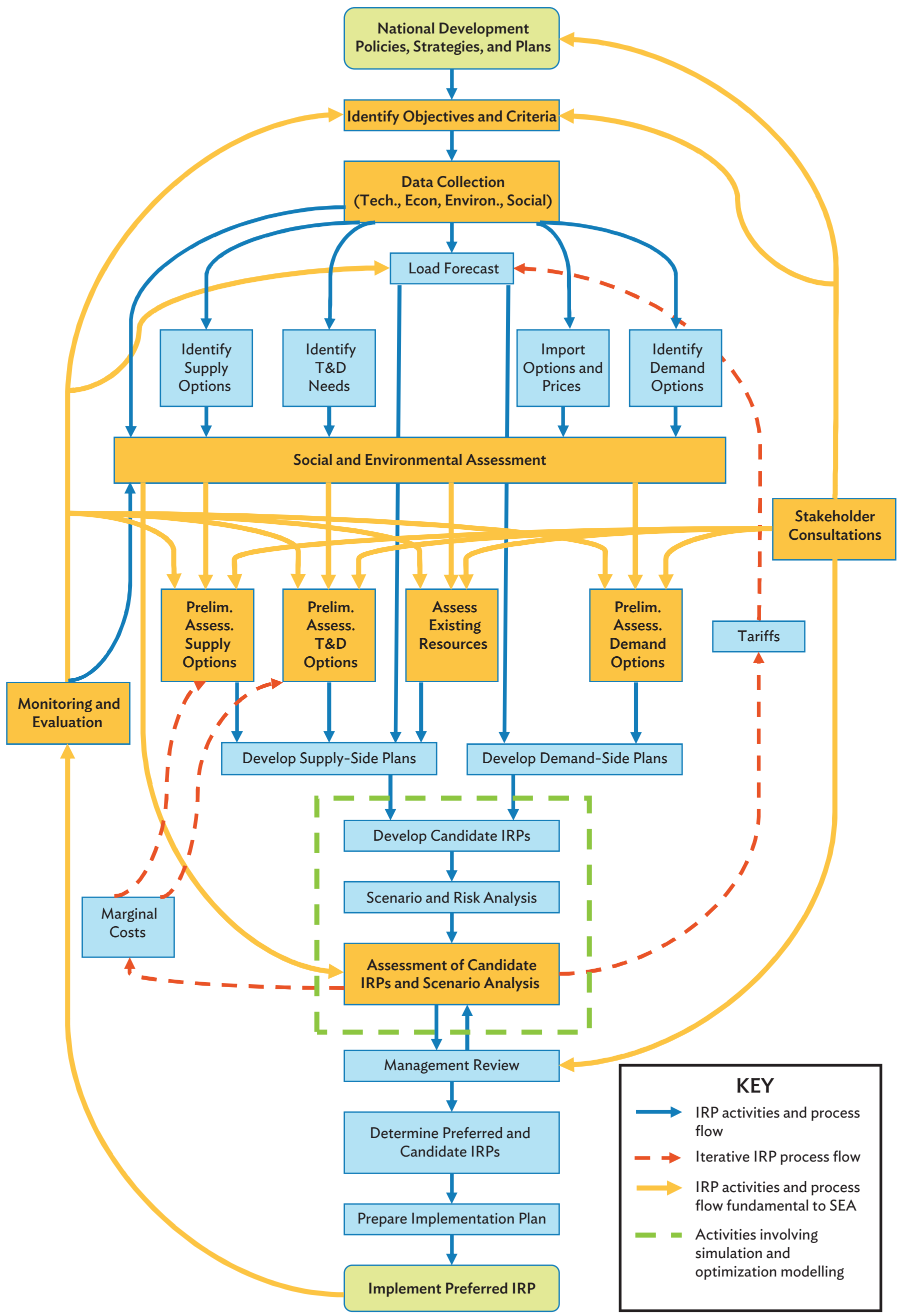
The previous subsection provided an overview of IRP: what it is, and where and how it is being applied. Consideration now turns to what constitutes international good practice for IRP in power planning.

Although there is considerable variation in the elements of an ideal IRP that are adopted by individual agencies around the world, the steps involved in an ideal IRP are reasonably well accepted in the industry and in academic circles. Where there is a divergence from the ideal, this is usually taken for rational reasons related to local circumstances.

Figure 1 provides a process flowchart for a typical IRP that follows good practice in the industry. The flowchart indicates those activities that are of particular importance when the IRP preparation is integrated with an SEA process.

The individual activities in the IRP preparation process are elaborated in the remainder of this subsection.

Figure 1: Typical Integrated Resource Planning Process Flowchart



IRP = integrated resource planning, SEA = strategic environmental assessment, T&D = transmission and distribution.
Source: Ricardo Energy & Environment.

IRP within an IRP with SEA Framework

TA 9003 has been unable to identify any jurisdiction that—as a matter of policy—routinely undertakes IRP with SEA for their national power system. The closest exceptions to this, however, are the PRC and—principally—Viet Nam.

Best Practice IRP Processes, Policy Instruments, and Frameworks

Process, Scope, and Objectives

IRP Planning Process

A fundamental initial step in the IRP planning process is to identify the relevant national policies and programs, together with identifying all the agencies with a significant bearing on developing and implementing the IRP. Good practice in IRP preparation typically involves coordination, collaboration, and consultation with these agencies, and other stakeholders, at key stages in the process. By making the IRP readily accessible to wider stakeholder groups—placing in the public domain the underlying objectives, criteria, methodologies, together with facilitating meaningful consultation—it is less likely that subsequent opposition during IRP implementation will arise. Subsequent subsections of this document provide further recommendations on consultation processes.

Scope of Planning

In establishing the IRP process, it is important that—in addition to involving the power utilities and the various agencies within the energy and/or power ministry—other government ministries and agencies are involved. For instance, these other bodies may include ministries of industry, planning, or environment. The gap analysis undertaken under TA 9003 has found that some GMS countries are particularly remiss in this regard.[17] Although collaboration across the agencies ought to be automatic, IRP preparation is often undertaken without reference to EE&C or renewable energy specialists that reside within other ministries, for example. Where ministerial rivalries are deep-rooted and counter-productive, an interministerial body may be needed to ensure good cooperation and collaboration in the national interest. There is considerable interdependency between IRPs and other national plans (e.g., NDC commitments, oil and gas plans, EE&C plans, renewable energy plans, or rural electrification plans) and—perhaps under the guidance of an interministerial body—all these plans must be internally consistent and coordinated.

Although this document deals with national IRPs, it is important to note that some countries in the GMS devolve planning approvals for projects smaller than 15 MW or 30 MW to subnational governments. Mechanisms for ensuring reasonable consistency across the two levels are to be encouraged, while noting that the location and modularity of smaller projects have advantages for IRPs.

17 ADB. *Integrated Resource Planning with Strategic Environmental Assessment in the GMS. Gap Analysis Report – Final.*

It is acknowledged that there is already appreciable transmission interconnection across national borders in the GMS, although overwhelmingly this is on a bilateral basis to export power from a project in one country to a utility in another. Although the RPTCC is encouraging other forms of trade and working toward establishing networks and systems that will facilitate such trade, there is no meaningful power system planning in 2020 that transcends national boundaries in the GMS.

The scope of an IRP includes the planning horizon, the frequency of updates, the precise content of the IRP presented for review and approval, and the policy instruments that are often prescriptive on these topics. IRP rules in US states typically include the planning horizon, which is usually 10, 15, or—most commonly—20 years. Some countries (e.g., Viet Nam) split the planning horizon, with the early years planned in considerable detail, while the later years are planned on a more circumspect basis. This is typical because demand forecasts and assessments of available technologies can be subject to significant uncertainties beyond 5–10 years in the future. Some countries do not specify the planning horizon, retaining flexibility.

IRPs need to be updated periodically to reflect changes in the various factors and parameters that have a bearing on constituent investments, sequencing and timing, etc. These factors and parameters may include load forecasts, fuel prices, capital costs, electricity market conditions, environmental regulations, etc. IRP updates are typically every 2–5 years. IRP updates can be expensive, and developing countries often require donor support—which works against frequent updates—and in such cases, 5 years is more likely. With the rapid rate of change in the sector economics—not least that caused by disruptive technologies—5 years is a very long time, during which previously viable technologies can become stranded assets. Countries with high rates of unsolicited hydropower IPP submissions (e.g., for export-oriented projects) may opt for more frequent PDP updates since the pipeline of projects can change very quickly. Volatile markets and rapid technological change suggest frequent updates, e.g., every 2 years, and this frequency is common in the US.

Other areas of IRP scope where policy instruments often venture include:[18]

(i) mandating that plant retirements are scheduled;

(ii) mandating that specific renewables are considered;

(iii) mandating that specific EE&C and DSM measures are considered; or

(iv) mandating the consideration of brown-field sites for new infrastructure.

Setting Objectives

Objectives for the power planning process are typically described in qualitative terms, whereas quantitative criteria are used to measure the situation in respect of each

---

18 Synapse Energy Economics Inc. 2013. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* USA.

objective. National development objectives and management strategies, in addition to any subnational objectives, need to be captured in the IRP preparation process.

Table 1 shows a potentially long list of objectives, some of which may be conflicting. Prioritization of objectives is required at the outset, which ought to be based on multicriteria analytical techniques that consider the concerns of stakeholders.

Table 1: **Potential Objectives for Inclusion in an Integrated Resource Plan**

Objective	Description
Service reliability	Addresses the frequency and duration of service interruptions to supply. Criteria may include loss of load probability (LOLP), loss of load expectation (LOLE), energy not served (ENS), etc.
Cost minimization	A common criterion in IRP preparation—or more specifically a fundamental principle—is that, subject to risk assessment and social and/or environmental considerations, the total discounted capital and recurring costs—in economic terms and including externalities—should be minimized, i.e., least cost.
Robustness and flexibility	Many factors such as costs and outlooks on environmental sustainability can change very quickly and plans are preferable that are robust against such changes or sufficiently flexible in response.
Diversity of supply	A key approach to ensuring a plan that is reasonably robust and flexible is to diversify the plant mix so that it is not too heavily dependent on particular fuels or technologies.
Energy security	Countries often avoid being overly dependent on neighboring countries due to the risk of supply disruptions. Thailand, for example, has a planning criterion that limits import dependence to a certain percentage of peak demand.
Electrification rate	Countries with electrification rates substantially below 100% may set targets for improving the rate. The electrification targets should be—but are not in all cases—taken into consideration in the IRP. Rural electrification plans are often prepared separately, in which case they should be integrated with the IRP.
Reducing the cost of electricity to end users	The affordability of electricity to low-income households has an impact on social welfare. Besides, nations in the process of industrialization compete internationally for inward investment, and electricity tariffs are a factor.
Reducing sector inefficiencies, such as losses	Some countries endure high technical losses due to under investment in transmission networks and/or dispersed generation. Some countries also suffer unduly from high non-technical losses due to various reasons.
Welfare benefits and costs	There are economic benefits associated with expanding supplies. For existing customers, this is assumed to equate to the product of the additional consumption and the applicable tariff. For new customers, where supplies displace more expensive alternatives, the benefit is based partly on willingness-to-pay principles. Social costs due to relocation or loss of livelihoods are to be minimized and, in any case, monetized and captured in the analysis.
Environmental impacts	Good practice is to include the cost of any environmental mitigation measures alongside other direct costs for plants. External costs due to CO_2, pollution, etc., should also be included. Projects likely to cause major and controversial impacts should be avoided.
Local resources and technology acquisition	Governments often have priorities that include job creation, e.g., in mining coal. Priorities may also include building businesses and creating employment in growth sectors such as wind and solar energy.

CO_2 = carbon dioxide, IRP = integrated resource plan.
Source: Ricardo Energy & Environment.

The set of objectives selected should aim to address short-, medium-, and long-term goals. In the interests of ensuring transparency and accountability, the objectives and related criteria should be published for stakeholder scrutiny so that conflicts later can be avoided.

Stakeholder concerns should inform the power planning process, and thorough consultation processes are a key element of an IRP, as they are for any nationally significant infrastructure. Local communities often have very different perspectives and objectives to those of central planners, but should not be ignored so that late-stage challenges that may delay plan implementation can be avoided.

Table 1 presents some possible objectives for inclusion in an IRP, together with a brief description and related criteria.

Demand Forecasting

General

Due to the importance of the demand forecast to the validity of the IRP, the forecast should ideally be centered on three key principles:

(i) a clear set of underlying assumptions;

(ii) a relevant and scientifically based methodology; and

(iii) dependable data.

In the interests of transparency and accountability, data sources and methodological assumptions for the demand forecast should be documented in clear detail.

The demand forecast—such as for EE&C and DSM—must be prepared on a business-as-usual (BAU) basis. The effect of future demand-side measures will be determined later—by striking a balance between the cost of energy savings and the cost of additional supply—at the margin. BAU, however, requires consideration of the scheduled retirement of any demand-side initiatives.

Data Requirements

The projections of demand should be for a period greater than the planning horizon of the IRP. The forecasts of demand underpin the IRP, and although multi-year forecasts are rarely accurate to a high degree, they must be based on data that is both very detailed and as accurate as possible. There is a greater likelihood of the resulting IRP being both robust and flexible if prepared with due rigor and using well-considered scenarios of how the future will turn out.

Forecasts start with a thorough understanding of all key data in the base year, which is usually the most recent year for which there is complete data. To help with understanding trends and linkages, as many years of historical data as possible should also be compiled. There are two basic categories of data :

(i) Data relating to electricity sales, energy end-use data, and power output from the generation portfolio:
   (a) data relating to the energy sold to end users, by geographical area and by customer class. The number of customers by class and by area is also important;
   (b) aggregated and disaggregated (days, weeks, months, and years) data on power output from the generation portfolio and cross-border trade. Load curves that identify system peak and off-peak periods are extremely useful to planners;
   (c) data on forced and unforced outages by generation unit;
   (d) studies that help differentiate losses into technical and non-technical classifications; and
   (e) energy end-use data are extremely important in an IRP due to the fundamental status of the demand side. Load curves for the different customer classes are particularly useful but may require data-logging on dedicated feeders.

(ii) Data that influence electricity demand:
   (a) economic data, e.g., gross domestic product (GDP), with disaggregation by economic sector; and
   (b) demographic data, e.g., population and number of households.

In addition to raw data, planners and/or forecasters need to foster a qualitative understanding of the factors behind the data, such as urban migration, increasing life expectancy, reducing birth rates, smaller households, or ownership of appliances. An increasingly important consideration is the technological factors influencing an economy's energy intensity since energy efficiency technologies such as LED lighting are helping countries reduce their energy intensity.

A general point is that because a forecast is only as good as the data upon which it is based, the relevant agencies should monitor the key data on an ongoing basis, rather than solely at the outset of the IRP preparation process. This provides more time to correct anomalies in the data or to gain a better understanding of apparent trends and linkages. The development of load curves by data-logging can be time-consuming, for instance. A good example of constant monitoring is in Thailand, where a load forecasting subcommittee under the Energy Policy and Planning Office undertakes an annual update of the country's load forecast.[19]

---

19 ADB. 2015. *Integrating strategic environmental assessment into power planning*. Manila.

Forecasting Methodologies
The basic methods used to forecast demand include one or more of the following:

(i) trend forecasting,

(ii) econometric forecasting, and/or

(iii) end-use forecasting.

Each of these approaches has advantages and disadvantages, and a combination of methods may provide better results.

Trend forecasting assumes that past rates of change will continue. Although this approach is relatively straightforward and possibly has merits for short-term forecasting, the rapid rates of change in technologies and lifestyles render this approach largely unsuited to long-term forecasts for IRP purposes.

Econometric forecasting considers linkages between electricity consumption and economic and/or demographic factors. It has historically been popular with power planners, although an important caveat is that the methodology requires parameters such as the price elasticity of demand and the income elasticity of demand. Country-specific evaluation of these parameters requires a long, detailed, and very consistent historical record of sales, economic growth, and electricity tariffs, together with a thorough understanding of factors behind any anomalies in the data, e.g., due to reclassification of customer subclassifications. Elasticity parameters can be obtained from academic studies involving multiple countries, but with the risk that national characteristics differ from those of the countries sampled. The econometric approach has suffered from the same failing as trend analysis, in that new technologies and consumption behavior make it unlikely that the parameters based on historical data are entirely reliable for projecting future demand.

End-use forecasting is a bottom-up approach that constructs estimates of electricity demand by considering the end-use purpose of the electricity. The method is extremely detailed and practical, with the caveats that it requires considerable volumes of data and constant application by dedicated forecasters to keep abreast of technological and behavioral developments. Software packages are available to assist with this approach, subject to the caveats raised above, and these models can be expensive. A key advantage of this bottom-up approach is that it readily facilitates the analysis of EE&C and DSM initiatives, which makes it particularly appropriate for IRPs.

One safeguard against the inherent uncertainty of demand forecasts is to prepare alternative scenarios of demand. Base, high-, and low-demand cases are typically prepared. Forecasters should use the base case as the best estimate of how key parameters will turn out over time. High- and low-demand cases should not center on arbitrary differentials from the base case (e.g., plus or minus 25% of the base case figures). Instead, they should be based on rational assessments of how key parameters—such as fuel prices, economic, and population growth—may vary from the assumptions in the base case. The scenario approach is useful for developing robust and flexible IRPs.

Supply-Side Options

Generation Options

A key element in preparing any PDP is the identification of supply-side options and any related infrastructure such as road or rail access, or fuel pipelines. Even a moderately-sized power system may have supply-side options that number in the hundreds. It is a distinguishing feature of an IRP that the preparation process should consider a comprehensive set of options, rather than arbitrarily limiting the options to familiar technologies and large-scale power plants.

It is helpful to distinguish generation options between

(i) centralized or non-locational power plants, typically large power stations that feed the main power grid; and

(ii) distributed or locational power plants, typically in off-grid areas or where there are transmission constraints in the main grid.

A wide range of generation technologies are used in both cases, but the largest plants use nuclear, coal-fired steam, and combined-cycle gas turbines, and large hydropower is generally confined to feeding the main grid. Diesel engines and smaller renewable facilities are more common in local situations. Increasingly, grid-scale wind farms, solar photovoltaic arrays, and dispatchable battery storage are being used to feed the grid. In off-grid situations, combinations of technologies are often employed, especially where intermittent renewable sources such as wind and solar form part of the mix.

Distributed generation in the form of rooftop solar photovoltaics for individual residences or small-scale facilities for relatively small communities are becoming increasingly common and are also becoming an increasingly cost-effective alternative to grid reinforcement or grid extension—especially in tandem with battery storage.

Planners and system operators usually categorize generating plants according to how they operate within the daily, weekly, or annual load cycle:

(i) **Baseload plants**. Typically operate for 24 hours/day, 7 days/week, and although these plants normally have high capital costs and relatively low marginal costs, they are unsuited to rapidly ramping their output either up or down as network demand changes.

(ii) **Mid-merit plants**. May not have marginal costs as low as baseload plants but are designed for load-following, as demand fluctuates, and are also better-suited to shutting down altogether— typically once or twice per day—during low-demand periods.

(iii) **Peaking plants**. Provide power to the system when demand is greatest. These plants typically have relatively low capital costs but higher marginal costs than either baseload or mid-merit plants. In larger systems, open-cycle gas turbines are often used to provide peaking capacity, while in smaller systems, high-speed or medium-speed diesel generators are often used.

In addition to understanding how each technology may contribute to meeting demand, planners need to consider the supply chain for each supply-side option. This may include oil and gas terminals, gas pipelines, coal mines, or railways.

Transmission and Distribution Infrastructure

Transmission and distribution (T&D) network expansion is an important consideration in an IRP. T&D expansion has to keep pace with the growth in demand. Timely transmission investments may also be needed to avoid transmission constraints arising from major new loads or major, location-specific generation plants such as a large hydropower station.

Emissions and Waste Considerations

Thermal generation technologies—particularly those using fossil fuels—often produce various polluting waste products, e.g., nitrogen oxides (NOx), oxides of sulfur (SOx), particulate matter, ash, etc. Planners must ensure that the costings for these power plants include the cost of all environmental mitigation measures required to meet prevailing standards of the country in question. It may also be the case that the lenders for projects require higher environmental standards than those in the recipient country.

In addition to the internal costs of pollution mitigation measures, IRP preparation requires that the associated external costs be also considered in the analysis. Carbon dioxide (CO_2) and other GHGs need to be quantified in terms of their metric tons of carbon dioxide equivalent (tCO_2e), which will vary with the fuel characteristics and the efficiency at which the plant operates. Applying a cost to the CO_2 emissions requires a decision on the most appropriate costing methodology; some authorities use values based on carbon trading markets, while others use values based on estimates of the social cost of carbon. The social cost of carbon estimate valuation is typically much greater than the carbon trading market valuation.

Other externalities may include the cost associated with the adverse health impacts due to stack emissions, or the permanent loss of livelihoods when land is inundated by storage reservoirs or acquired for ash tips.

Attributes of Supply Options

Overview of Resource Attributes Before assessments can be made to arrive at alternative IRPs, it is necessary to compile qualitative information on the various supply-side options. Table 2 highlights some of the most important attributes to be collected (footnote 11).

Table 2: **Important Supply-Side Attributes**

Capital cost	Plant capacity	Plant capacity factors
Fuel costs	Forced and unforced outage rates	Initial and recurring foreign exchange requirements
Non-fuel O&M costs (fixed and variable)	Economic life	Environmental and social impacts
Efficiency/heat rate	Decommissioning costs	Ramping and dispatchability

O&M = operation and maintenance.
Source: Ricardo Energy & Environment.

Key Attributes of Renewable Resources With an ever-increasing focus on GHG reduction from the global community, non-hydropower renewable energy is experiencing rapid penetration in the generation mix of both developed and developing countries. Denmark leads the way with more than 50% renewable energy, and several countries including the US have achieved at least 10% renewable energy. There are several distinguishing features associated with renewable energy plants, particularly those of an intermittent nature, such as wind and solar. Consequently, it is important to list their key attributes separately. The resource attributes and their relevance to IRP preparation are outlined in Table 3.[20]

Social and Environmental Considerations Supply options need to be assessed to establish, quantify, and monetize any possible adverse social and environmental impacts. It is a fundamental objective of IRP with SEA that the SEA should screen out any supply options that are unacceptable to society. Where negative impacts are identified, provisions for impact mitigation need to be developed and costed. Generally, full consideration of social and environmental impacts serves to make renewable supply options more attractive relative to conventional supply options. Demand-side options such as EE&C and DSM should also benefit.

Because of the large number of individual supply options under consideration, and the effort required to assess social and environmental impacts, it is advisable that these assessments are only undertaken for those options shown to be economically and technically viable.

Preliminary Assessment of Supply Options Once data on the numerous supply options have been assembled, the options need to be evaluated to produce a subset of options sufficiently attractive to be considered as candidates for inclusion in one or other of the alternative IRPs.

There are no fixed methodologies for this screening. One approach is to do a preliminary screen out of unsuitable options based on levelized cost of energy (LCOE), resource considerations, technical uncertainties, etc. Screening curve

[20] D. Logan et al. 1984. *Modeling Renewable Energy Resources in Integrated Resource Planning*; RCG/Hagler, Bailly, Inc.; National Renewable Energy Laboratory. Washington, DC.

Table 3: Resource Attribute Relevance to Integrated Resource Plan Preparation

Attribute	Relevance
Capability	Limitations on the technology's ability to supply power or reduce demand during a period under normal conditions. Limitations may include contractual limits, plant capacity rating, and limitations due to fuel supply constraints or hydropower reservoir constraints. Renewable resources, particularly intermittent ones such as solar and wind, are different from conventional generation technologies in this respect.
Availability	Output reductions due to scheduled or unscheduled plant outages. Intermittent technologies such as wind and solar are subject to random fluctuations, in addition to predictable patterns such as those of a diurnal and seasonal nature.
Efficiency	Efficiency (or heat rate) is as important to thermal technologies fueled by biomass as it is to those fueled by fossil fuels. Efficiency also applies to wind turbines and photovoltaic modules.
Dispatchability	A dispatchable plant is one where the network operator can control the output of the plant in real time. Operators prefer full dispatchability because it gives them the greatest operational flexibility. In contrast, the network operator has no control over a non-dispatchable plant and—generally—must receive whatever energy is produced, when it is produced. A distinction can be made between schedulable and curtailable resources. Schedulable is where the network operator can specify the output in advance, on an hour-by-hour basis. In contrast, the network operator has no control over a curtailable resource, except under certain minimum loads, at which point the operator has the right to decrease or curtail output at a moment's notice. Dispatchable resources are useful for load-following duty, or in some instances to provide spinning reserve in the event of sudden plant failures elsewhere or rapid increases in demand. The inability of resources with negligible marginal cost, such as wind or solar, to provide full dispatchability is of less importance to network operators if they can be curtailed under minimum load conditions. Grid connection agreements often stipulate that the output from wind or solar facilities may be curtailed at certain times for network operation reasons.
Location	The location of a supply resource influences capital spending on transmission and distribution reinforcements, the cost of technical losses, and local service reliability. It is often advantageous if smaller supply options can be close to substations, by deferring transmission reinforcements. Renewable resources are well placed to provide locational benefits to the integrated resource plan (IRP). However, it may be the case that the best renewable resources are distant from the demand centers and thus require additional cost to be integrated into the system. Even closer to the customer's socket, supply options on the premises serve to defer both transmission and distribution reinforcements. In 2020, few expansion planning software packages can recognize many individual locations and thus capture the full benefits of renewable energy sources.
Modularity	Modular options such as solar parks involve incremental capacity in relatively small blocks, and often with short lead times relative to large-scale conventional generation technologies. The advantages of modularity to IRP preparation is that it avoids temporary over capacity arising from the commissioning of large plants and that they help to minimize exposure to completion risk and other risks associated with major new projects. Renewables such as solar and wind have considerable potential for providing modularity advantages. However, as covered later, few expansion planning software packages can capture these advantages.
Costs	The inclusion of significant penetrations of various renewable energy technologies in the plant mix serves to diversify the risk of exposure to an escalation in costs such as fuel.
Incentives	Governments have used various forms of incentive to promote supply-side (as well as demand-side) options that have distinct merits to help reduce greenhouse gas emissions and to thus help meet international commitments to mitigate climate change and global warming. In assessing alternative IRPs, it is important to identify the beneficiaries of the incentives and to account for them correctly in the analysis.

continued on next page

Table 3: *continued*

Attribute	Relevance
Risk	All attributes in this table are subject to some degree of risk and uncertainty that actual out-turns in costs and planning parameters are at variance with assumed values. Sensitivity studies and scenario analysis should be undertaken on IRP alternatives to gauge their robustness against these risks. If undertaken rigorously, the sensitivity studies ought to establish the economic advantages of risk diversification. Each type of supply option, both conventional and renewable, have sets of risk factors, some of which are common to all, and some are unique to a technology or specific project. Fuel and technology diversity help mitigate risk exposure.
External costs	Externalities can include both costs and benefits experienced by others due to power development decisions for which the others neither make nor receive monetary transactions. It is a fundamental element of an IRP that externalities should be fully evaluated and the costs (or benefits) assigned to the supply option from which they originate. It is extremely important for renewable supply options that the external costs of fossil-fueled options are fully captured and by a carbon costing methodology that provides a full reflection of the long-term environmental and societal impacts of climate change and global warming.

Source: Ricardo Energy & Environment.

analysis can play a role as cost considerations need to take account of the potential role of an option in the system, i.e., baseload, mid-merit, or peaking.

Demand-Side Options

Overview of Demand-Side Options

Demand-side options include both EE&C and DSM initiatives. EE&C initiatives seek to reduce electricity consumption through measures such as incentives (such as subsidies or tax concessions), public awareness campaigns, and compulsion (e.g., the introduction and enforcement of instruments compelling the sale and use of energy-efficient equipment or building products). DSM initiatives generally seek to modify the load curves by changing the timing of electricity consumption, typically to transfer some demand from peak to off-peak periods.

As with supply-side options, the review of demand-side options starts with the compilation of all potential demand-side options, together with their cost and performance characteristics. Generally, all options involve initial and/or recurring costs for government, utility, or the end user, and sometimes all three. For example, the promotion of energy-efficient buildings or equipment through subsidies requires government to finance the program. Public awareness campaigns—through TV, radio, and newspaper advertisements—requires the government or the utility to pay for these advertisements. The introduction and enforcement of minimum energy performance standards for electrical appliances require trained inspectors and access to testing laboratories, which constitutes a cost to government.

An important distinction between demand-side and supply-side options is that the cost and benefit streams of demand-side measures are considerably more uncertain. Targets may be set for a particular target, but the time required to arrive at that target, and the financial resources required to reach the target, are difficult to gauge. The uncertainties can be reduced by running pilots, in some instances, or by studying the experience of other countries. However, EE&C and DSM initiatives that have worked in one country have often had disappointing results in others. Governments need to remember that measures requiring end users to incur costs for energy-efficient equipment, for example, are severely disadvantaged if the electricity tariff is set well below the full cost-recovery level, i.e., is being subsidized. Unless the tariff is reasonably close to the true economic cost, the market for EE&C is adversely distorted.

Table 4 provides an indication of the range of demand-side options available for consideration in an IRP, divided into four broad categories (footnote 11).

Attributes of Demand-Side Options

As with supply-side options, before assessments can be made to arrive at alternative IRPs, it is necessary to compile qualitative information on the various demand-side options. Table 5 highlights some of the most important attributes to be collected (footnote 11).

Preliminary Assessment of Demand-Side Options

The cost-effectiveness and practicality of demand-side options vary with the characteristics of individual nations. Some measures will not be economic where

Table 4: Demand-Side Options Available for Integrated Resource Plan Consideration

Category	Demand-Side Options
Information and/or incentives for efficiency in end uses of electricity	Dissemination of awareness messages on the societal and environmental advantages of EE&C. Time-of-use (TOU) electricity tariffs that reflect or accentuate the differential in the marginal cost of supply during peak, standard, and off-peak periods. However, the additional cost of the requisite metering can be prohibitive for residential and other low-consumption customer groups.
Energy-efficient technologies	These are technologies that reduce energy consumption, and those that reduce demand at peak times are of interest. Energy-efficient technologies are evolving in all customer categories and include: (i) more efficient electrical appliances for households and offices; (ii) LED lighting; (iii) better roof, wall, and window insulation in buildings; (iv) more efficient electric motors; and (v) more efficient street lighting, etc.
Fuel-switching technologies	Of greatest relevance for IRPs are options that substitute another fuel for electricity to reduce electricity demand or, at least, reduce peak demand for electricity, e.g., passive solar water heaters.
Load management	Load shifting measures to transfer electricity consumption from peak to off-peak periods: (i) Water heater controllers, including ripple control, activated by the utility to switch-off heaters during peak periods. (ii) Interruptible electricity tariffs for high-volume consumers that are offered a discounted tariff in return for allowing the utility to disconnect all or part of the consumer's supply when system demand approaches the utility's available capacity.

EE&C = energy and efficiency conservation, IRP = integrated resource planning, LED = light emitting diode.
Source: Ricardo Energy & Environment.

Table 5: **Attributes of Demand-Side Options**

Capital Cost	Reliability and Economic Lifetime
Operating costs	Efficiency
Applicability	Environmental and social impacts
Fuel type (for fuel-switching options)	Foreign exchange requirements and scope for local input

Source: Ricardo Energy & Environment.

there are deliberate policies to maintain electricity tariffs well below cost-recovery levels, for example. Nor will product labeling approaches have much prospect of success if there is little short- or medium-term prospect of adequate controls on imported appliances. Consequently, preliminary screening of options is advisable, using a combination of quantitative and qualitative criteria.

Preliminary assessment methodologies may include

(i) life cycle cost of the demand-side measure, in comparison with the incumbent alternative;

(ii) cost (i.e., average over the measure's life cycle) per unit of energy saved;

(iii) cost per unit of CO_2 savings; and

(iv) qualitative assessments on the acceptability of the measure to customers.

A useful technique available to planners is to construct a cost of saved energy curve. Using this cost per unit of energy methodology, the curve (cost per kWh saved versus aggregate energy savings) is constructed in order of cost saved, starting with the lowest cost measure. This curve provides an indication of where the cut-off lies, i.e., where the cost of energy saved equates to the cost of electricity supply. Other evaluation techniques are available, however; the California Public Utilities Commission applies five separate tests to select demand-side programs: participant tests, rate payer impact measure tests, total resource cost tests, societal tests, and utility cost tests.[21]

In undertaking these assessments, care needs to be taken with assumptions on the rate of uptake of demand-side options. Experience in other countries should be considered, together with a comparison of national characteristics in each country, such as the level of electricity tariffs.

[21] California Public Utilities Commission. 2001. *California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects.* San Francisco. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7741.

Assessment of Candidate Plans

General

Developing a plan involves selecting combinations from the feasible options—including their commissioning dates—to balance supply and demand at a minimal economic cost to the nation.[22] The plan will also need to accord with a range of constraints of a technical, financial, environmental, and regulatory nature. Technical approaches to this fundamental aspect of preparing an IRP vary widely from one utility and/or agency to another. Some utilities use an optimization model to prepare the optimum plan, i.e., one that is the least economic cost. Due to the limitations that exist in most proprietary software models, experienced planners and/or modelers use workarounds that, to some degree, rectify the shortcomings of their model. Some agencies find it advantageous to use different models for individual aspects of the optimization process. The use of optimization software is far from universal, however, and many other utilities and/or agencies build their demand- and supply-side plans separately and combine these into an integrated plan. An intermediate approach adopted by yet other utilities and/or agencies is to simultaneously evaluate demand- and supply-side options to iteratively construct an integrated plan that satisfies specific cost-effectiveness tests.[23]

Supply Plans

Candidate supply and demand plans can be compiled once data on the various options have been assembled and preliminary screening undertaken. The plans aim to meet the demand forecast in each of the various scenarios selected (e.g., base, high, and low).

A supply plan will meet the profile of forecast demand over the planning horizon using the supply-side resources that passed the preliminary screening. Assembling a manageable number of alternative supply plans requires judgment by the planners, assisted by spreadsheets and proprietary software tools. Important considerations in this part of the process include the following:

(i) location of the supply option relative to demand centers and the national grid;

(ii) timing of commissioning relative to demand, while taking full account of the lead time for the supply option;

(iii) costs and financing mechanism, e.g., public or public–private partnership, which may influence the lead time to commissioning;

---

[22] D'Sa from the International Energy Initiative notes that many agencies preparing IRPs, including most of those in the US state utilities, work in terms of financial costs to the utility, rather than economic costs. The use of economic costs is more consistent with best practice and is generally required by the guidelines of major development agencies such as the World Bank and ADB.

[23] National Renewable Energy Laboratory. 1994. *Modeling Renewable Energy Resources in Integrated Resource Planning*. Boulder.

(iv) retirals, repowering, or life-extension investments for existing plants within the planning horizon will need to be considered; and

(v) plant margin (or other parameters) required to ensure optimum levels of system reliability.[24]

In preparing alternative supply plans, numerous resource configurations will need to be considered. Given the commitments of countries to reduce CO_2 emissions relative to a BAU scenario, these alternative supply plans will need to consider varying levels of renewable capacity since the actual levels of energy generation by each technology—and hence the level of CO_2 generated—until simulation is undertaken.

Assessing Supply Plans

Overview Each of the alternative supply plans needs to be assessed individually. Key criteria in these assessments include the reliability of the plan using a measure such as the LOLP. The total capital cost and the present value of all capital and operating costs are required. Environmental impacts need to be quantified and aggregated.

While it is possible to undertake the assessments using spreadsheets, the complexity of plans for even relatively modest power systems is such that sophisticated software tools are routinely used for this important aspect of IRP preparation. These subsections focus on approaches and models suitable for the required purpose, and the challenge for modelers when significant penetrations of renewable capacity are under consideration.

Expansion Planning Models At any time during the planning horizon, system operators will aim to dispatch the available units in the most economic combination; sometimes referred to as merit order, i.e., dispatching units in order of lowest marginal operating cost until enough capacity is called to meet demand at that time. There are numerous caveats to this principle, however, and operators must also consider factors such as transmission constraints in the network, contractual arrangements with any IPPs, and the necessity to maintain adequate spinning reserves. Increasingly, a further factor to be considered by system operators is that the system may include non-dispatchable capacities such as wind and solar photovoltaics.

Many proprietary software suites for expansion planning include a simulation module, i.e., a software tool that simulates the dispatching process. These software suites usually also include modules that will optimize a supply plan according to the objectives and constraints set by the planner and/or modeler.

---

24 With the notable exception of several US states, planners rarely use simple deterministic measures to set the required plant margin (e.g., 20% of maximum demand or the combined capacity of the two largest units in the system). Instead, measures such as loss of load probability (LOLP) are preferred. The optimum LOLP is established by considering the energy not served (ENS) in a given year, together with the cost of unserved energy (CUE). Simulation software is typically used to estimate on a probabilistic basis the system reliability (such as LOLP or ENS) in each year of a plan. It should be noted that CUE values tend to increase as developing countries industrialize and as the population becomes more dependent on ICT.

Box On Generation Expansion Planning Models

Although candidate integrated resource plans (IRPs) can be constructed by hand, due to the size and complexity of most power systems, together with the extensive range of supply- and demand-side options with the potential for consideration, software tools are available that can generate and evaluate many different supply and demand combinations, e.g., Strategist, PROVIEW (a module in Wien Automatic System Planning [WASP] IV), CAPRICORN, Balmorel, GTMax, UPLAN, OptGen, PLEXOS LT Plan, e-7 Capacity Expansion, etc.

The various software packages have similarities but are often designed for specific types of system. It is therefore important to ensure that a package used for an IRP matches the system characteristics and the IRP objectives and constraints. Some US states, for example, are more highly focused on reducing greenhouse gas (GHG) emissions through the application of renewable energy and DSM than some other states.

The choice of generation expansion planning (GEP) model is influenced by issues such as

(i) good representation of hydropower systems (essential for most Greater Mekong Subregion [GMS] countries);

(ii) representation of demand forecasts (load duration curves or more realistic);

(iii) representation of dispatch optimization (typically at the kernel of the model);

(iv) reliability constraints (typically a key driver in the modeling);

(v) emission constraints (whether to price carbon, constrain emissions, or both);

(vi) policy constraints (including renewable energy policy);

(vii) transmission constraints (often an issue in rapidly growing networks); and the

(viii) level of interaction with transmission planning.

Other important factors to bear in mind include the ease of use of the software, the capacity building required to enable planning staff to use it effectively, and the commercial factors such as licensing costs.

The two main elements in a GEP model are simulation and optimization. Probabilistic simulation is extremely important where significant intermittent renewable energy capacity is considered. A range of algorithmic approaches has been adopted for optimization, the choice of which influences the speed with which the optimum solution is determined. Some of the more recent models, such as CAPRICORN and Balmorel, use mixed-integer linear programming (MILP), which facilitates large numbers of supply- and demand-side options to be optimized quite rapidly, compared to some of the other optimization algorithms.

GEP modeling has become much more complicated since the introduction of liberalized markets (electricity prices determined in a wholesale market) in some jurisdictions. In the US, for example, there is less emphasis on long-term expansion planning and a greater focus on the short- to medium-term profit of the utility owning the IRP.

Since GHG emissions are an increasingly important consideration, policies and objectives are likely to continue to evolve with the progression of global climate change. Consequently, GEP models will need to reflect these trends. Generally, the development of GEP models has struggled to keep pace with the evolution of the industry, and the need to accommodate the numerous attributes of large- and small-scale variable renewable energy and storage, etc.

As an exercise under ADB Technical Assistance 9003, the CAPRICORN program was used to investigate the technical feasibility of explicitly considering a range of externalities when mathematically optimizing electricity generation and transmission expansion plans. The exercise was conducted using the Vietnamese power system as an example and based on the data employed when deriving the current national Power Development Plant during 2015–2030 (Revised PDP VII).

continued on next page

Box continued

A feature of CAPRICORN is the capability to consider transmission reinforcements as options, e.g. where strengthening a transmission system or importing electrical energy may be more cost-effective than providing new generation facilities, and when export possibilities justify the introduction of greater generation capability than required solely to satisfy domestic demands. A further feature is the capability to take account of component dependencies, including choices between hydropower project variants, and the effects of constructing upstream storage reservoirs.

The CAPRICORN modeling for Viet Nam indicated that it is now technically feasible to take explicit and simultaneous account of externalities when optimizing integrated generation and transmission system expansion plans for large and complex systems. It also showed that there may exist potential cost savings by tailoring expansion plans to meet specific targets, i.e., by imposing emission, budget, and supply reliability constraints, rather than applying heuristic installed capacity and available energy margins. For large and complex systems, expansion plan optimization can require the solution of MILP problems of significant size, i.e., with up to 50,000 decision variables and a similar number of constraints. Moreover, with the latest computer capabilities and more efficient MILP solution algorithms, it is possible to contemplate optimizing the integrated development of regional systems, such as that constituted by countries making up the GMS.

Source: Ricardo Energy & Environment.

Very few expansion planning software packages have the comprehensive capability to adequately capture the key attributes of technologies that are increasingly prominent in recent IRPs (such as modularity, non-dispatchability, location, and externalities.) since most have been developed for the US market where IRPs are not undertaken to the ideal level. To assist planners in the preparation of IRPs that are consistent with national green growth and sustainable development policies, and to meet commitments of CO_2 reduction, better models and approaches are needed, especially with the handling of renewable supply options.

Modeling Renewables Intermittent renewable resources bring—in significant proportions—several important attributes that, if fully accommodated by the assessment process, will enhance their role in an IRP. It is therefore a suitable juncture to emphasize that the key issue underpinning each attribute in IRP preparation is cost since the fundamental objective of an IRP is to determine a combination of options that minimizes total economic costs (footnote 23).

The challenge for planners and modelers is that capturing the valuable attributes of renewables can be difficult. Few proprietary models were developed to cater for high levels of renewable energy in the plant mix, especially intermittent resources. The non-dispatchability attribute presents modeling difficulties, and it is also difficult to capture the modularity and the location.

Demand-Side Plans All available demand-side measures should be screened to identify the most attractive options to take forward for further assessment. The next step is to combine these into candidate demand-side programs that have the potential to deliver the cost, reliability, environmental, and other benefits associated with such measures and, due to which, IRP is superior to routine least-cost approaches. Delivering on a demand-side program requires a range of interventions from government or their utilities, the costs and timing of which are extremely relevant to an IRP. The candidate demand-side programs will probably include a combination of inducements to end users and compulsory measures, all of which will involve administrative costs, subsidies, etc.

A demand-side plan comprises one or more of the pre-screened demand-side programs. This plan details the activities to be undertaken by the implementing agency over a period of years. Assembling candidate plans requires consideration of the key attributes. Although all attributes can influence decisions on their inclusion in the plan, perhaps those requiring most careful consideration are the effectiveness of the program, together with the timing and persistence of the energy savings.

Assessing Demand-Side Plans The criteria for assessing demand-side plans are like those for supply plans. They include peak power and energy savings, costs, suitability, environmental impacts, etc. Of crucial importance to the analysis is how the cost of the plan compares with that of the supply-side options that it displaces. It is important to note that there are slight differences in approaches adopted by planners in how this balance is struck. Some authorities suggest that iteration of the IRP is undertaken until a balance is struck between the marginal cost of supply and the marginal cost of the demand-side measures. Planners may note that the marginal cost of supply is dependent on factors such as the voltage at which electricity is supplied to the end user. Individual demand-side measures often also target specific groups of end users. A slightly different approach is to balance the total resource cost of the demand-side plan with the total resource cost of the supply-side resources displaced. Yet another consideration is to understand from whose perspective these total resource costs are taken e.g., the utility or the customers. Incidentally, marginal costs are usually taken from the national perspective.

The US Agency for International Development (USAID) considers that the most accurate approach is to compare the avoided cost of energy saved through a demand-side plan, with the costs of energy determined from alternative IRPs that (i) include, and (ii) exclude the demand-side programs under evaluation.

Proprietary software tools or bespoke spreadsheet models may be simpler alternative methods of evaluating demand-side plans than extensive IRP modeling, especially when there can often be a high degree of subjectivity in the assumptions relating to the effectiveness of individual demand-side measures.

Assembling Candidate IRPs Planners adopt a wide range of approaches to determining their IRP. The size of the power system, the range of supply- and demand-side options, and the availability of models and modeling skills are factors in this choice. For all but the smallest systems, the literature on IRP good practice appears to have coalesced on an approach like the following:

(i) Set objectives and criteria.

(ii) Develop a demand forecast, without additional demand-side initiatives.

(iii) Develop supply-side options and screen against criteria.

(iv) Develop demand-side options and screen for cost-effectiveness.

(v) Develop a set of candidate IRPs, the sub-steps of which include:
  (a) Develop supply plans for each demand scenario and for any other variants in objectives and criteria. Importantly, this could include different values for the cost of CO_2; it could progressively screen out environmentally or socially controversial projects, e.g., large coal, large hydro; and it could include more optimistic take-up of EE&C or DSM measures by consumers.
  (b) Develop demand-side plans.
  (c) Develop candidate integrated plans (i.e., integrating supply plans and demand plans).
  (d) Evaluate the candidate IRPs.

When developing candidate IRPs—step v(c)—for all but the smallest systems, planners turn to sophisticated expansion planning software packages to construct and evaluate the demand and supply combinations. Individual software packages vary in their focus; some may recognize demand-side options as a distinct element of the model, whereas others may treat demand-side measures as a supply-side option with a negative capacity, but capital and recurring cost structures identical to those of a supply-side option.

Ideally, several distinct candidate IRPs should be developed. As an example, in preparing their 2013 IRP, PacifiCorp—a utility in the Pacific Northwest of the US—19 scenarios were applied across five different transmission scenarios, yielding 94 different variations of resource portfolios (footnote 10). PacifiCorp's resource measures included a diverse range of thermal and nuclear generation, renewables, various dispersed or locational generation technologies ranging from rooftop solar photovoltaics to gas turbines, various energy storage technologies, and a diverse range of EE&C and DSM measures.

Assessment Criteria The assessment criteria for the candidate IRPs will be very similar to those presented above for evaluating supply- and demand-side plans (e.g., reliability, environmental and social impacts, capital expenditure requirements, the present value of total costs, tariffs, marginal costs). They should also cover the objectives—both quantitative and qualitative—developed at the outset of the planning exercise, ideally in collaboration with relevant agencies.

Assessment and Selection Though a simplistic logic may suggest that the candidate IRP should adopt the least discounted total economic cost, the wide and diverse range of objectives for the IRP—some of which are quite subjective and qualitative—suggest that good practice is to undertake a further round of analysis before selecting a preferred IRP. Management—which may include stakeholder agencies beyond the planners themselves—is likely to engage closely with this final assessment and selection process.

Since many of the parameters used to prepare an IRP are subject to risk and uncertainty, an important element during the assessment of the process is to undertake risk analysis and sensitivity studies. By considering different scenarios and sensitivity analyses, an optimum diversity should be achieved in the IRP that is robust against reasonable outturns. Typical risks in IRPs that are addressed by scenario analysis or sensitivity studies include fuel prices, demand growth, electricity prices (where a market exists), hydrological variability, and environmental regulations—including those on GHG emissions.[25] Similarly, some of the IRP objectives may be conflicting, and scenario analysis will help guide stakeholders and decision makers to an optimum way forward.

Utilities are known to employ multiple decision support systems to select their preferred IRP. Among these are multi criteria analysis or multiple attribute analysis. Each of these techniques requires a degree of subjectivity in the weighting assigned to the different criteria or attributes, and to the scores awarded to each of these. Subjectivity can be reduced through consultation and engagement with stakeholders, however. The techniques are well documented in the literature and good practice includes developing a consensus between stakeholders on the subjective elements.

For some US IRPs, the preferred IRP must solve two key challenges that include the mitigation of future costs and risk, given a set of environmental constraints. An efficient frontier helps determine the trade-offs between risk and cost.[26] The efficient frontier is developed by undertaking sensitivity studies on each of the candidate IRPs. Structured analyses will provide a risk value for each candidate IRP—taken from the distribution of discounted costs from the sensitivity studies—to be paired with the central discounted cost of that scenario. If not already included in the software package used for the optimization modeling, spreadsheet add-in tools such as @Risk and Crystal Ball are available.

Preferred and Contingency IRPs Although IRPs have planning horizons typically in the range of 10-20 years, changing circumstances mean that IRPs need to be updated every 2-5 years. Consequently, the current IRP effectively functions as a guide for relatively short-term decisions, e.g., when to commission a new power plant, introduce new incentives for renewable energy or EE&C investments, etc. A preferred IRP is required to guide the nation's supply-side and demand-side activities in the short-term, while providing best-estimate plans for the longer term.

During the period between IRP updates, circumstances may change (e.g., major projects delayed for various reasons, demand considerably lower than forecast, or take up of a DSM measure much slower than estimated) and one of the alternative IRPs may become more attractive than the one previously selected as the preferred IRP. Some agencies designate specific contingency IRPs for these possible outturns.

25 A meeting of the Inter-Governmental Panel on Climate Change in Incheon, Republic of Korea (1–5 October 2018) raised concerns that the measures agreed in the Paris Agreement of 2015 may not actually limit global warming to the target of 1.5°C, which raises the prospect of tighter GHG emissions regulations in some jurisdictions at some point in the future.

26 Avista. 2009. *Electric Integrated Resource Plan*. USA.

Stakeholder Consultations

Importance of Consultations
The maintenance of adequate, reliable, and affordable electricity supplies is of great importance to government departments, commercial enterprises, educational institutions, community facilities, and households. In the interest of good governance, and to reduce the possibility of objections and late-stage delays to the implementation of projects in the expansion plan, good practice requires that thorough consultations be conducted with all key stakeholders.

Interagency Coordination
Ministries, such as those for finance, industry, energy (oil and gas departments), environment, welfare, agriculture, transportation, etc., will have an interest in plans for power expansion and operation. They will, moreover, welcome the opportunity to contribute to the planning process by providing their perspective on the objectives of the IRP. For example:

(i) industry may want more reliable supplies at a lower cost,

(ii) finance will have an interest in financial requirements,

(iii) environment will wish to minimize environmental impacts such as CO_2 emissions and air emissions, and/or

(iv) welfare will have an interest in affordability to poor households and expansion to unserved areas.

The planning process should include consultation with these ministries and departments on the objectives of the IRP at the outset. Some governments establish interministerial bodies, such as a working group, to have inputs to the process at key junctures in the process, which is an excellent example of good governance practice.

Consultations with Other Stakeholders
Government agencies and utilities are not the only stakeholders that have a keen interest in power expansion plans. Other interest groups include private investors in IPPs; financiers of IPPs; industries (represented through trade bodies), householders and members of the public; NGOs; and civil society groups representing environmental conservation interests, rural communities, low-income groups, etc.

By modern standards of good governance, it is no longer sufficient to consult with stakeholders at the very end of the IRP preparation process, when the plan is virtually complete; the IRP should be a transparent and participatory planning process, and stakeholders should be provided with the opportunity to contribute earlier, through public hearings for example.[27] Stakeholders should not be treated as simply

[27] Consultations associated with a strategic environmental assessment (SEA), conducted to good practice standards, provides stakeholders with the opportunity to contribute toward the broader issues.

a potential source of complaints that may lead to project delays and cancellations; consumer groups can also be a source of ideas and useful information.

IRP Implementation, Monitoring, and Iteration

The adoption of the preferred IRP is followed by the implementation process. The circumstances can change quite rapidly, and it is therefore prudent for monitoring and evaluation (M&E) procedures to be established, with a department designated for this specific task. In addition to monitoring progress with the implementation of supply-side projects and also demand-side initiatives, this department could be tasked with monitoring outturns in all the key parameters used in IRP preparation, such as demand growth, capital and operating costs, inflation rates, or exchange rates. Collating and analyzing demand forecasting data continuously is advisable, and other IRP planning criteria could be subject to the same continuous cycle.

If circumstances dictate, it may be advisable to switch the preferred IRP to one of the contingency IRPs. If multiple key factors change significantly, it may be prudent to trigger an IRP update, if the legal statutes stipulate a rigid cycle for such updates (e.g., every 5 years).

On the supply side, projects can be delayed for years—or even canceled—due to a wide range of reasons such as financial, legal, regulatory, or environmental. At the same time, with renewable energy and storage costs declining rapidly, comparative economics with conventional generation technologies can change equally rapidly. Also, if the legal frameworks permit unsolicited proposals, a developer may propose a viable project that had not been considered as a candidate in the IRP preparation.

On the demand side, EE&C and DSM initiatives may prove to be less effective than assumed in the IRP, which may lead to their cancellation or to additional financial and institutional resources required to support promotional activity. Internationally, agencies and utilities have developed a range of evaluation techniques to review the effectiveness of these demand-side initiatives which, inherently, are more difficult to assess than supply-side options.

Policy Instruments, Legal and Regulatory Frameworks, and Institutional Arrangements

General Aims

Government policies provide the frameworks for the ownership structure and regulation of power infrastructure and systems. Government policies can also establish the rights and responsibilities of all stakeholders in power planning and operation. The prominent strategic importance of a nation’s power sector is such that this planning and operation affects a broad range of interests across society. Whereas most countries have policies covering the planning and operation of the sector, it is less common for countries to integrate these with policies focused on sustainable growth. Nor is it common for countries to have suitable frameworks to achieve their policies in these regards.

Many countries and jurisdictions that prepare PDPs do not meet most of the qualities of an IRP that distinguishes them from a basic least-cost expansion planning exercise. Moreover, of those that have formally adopted IRP, a significant proportion do not follow all the individual practices that constitute good practice IRPs. Adopting only a subset of practices is not usually due to negligence on the part of planners; typically, it is due to conscious streamlining to focus on the elements proven to be of greatest significance to the planning process in that particular jurisdiction. In such instances, the administrators and planners would probably argue that their resulting expansion plans are meaningfully consistent with the ethos of IRPs.

The aim of this subsection is to provide recommendations on how to ensure that expansion plans are consistent with good practice IRP, to reliably achieve truly sustainable expansion plans without exposing the process to arbitrary departures from good practice, unless with very good reason. As subsequent subsections of this document will demonstrate, there are elements of good practice IRPs which, if any are omitted, can result in an expansion plan that is exposed to special interest groups, incumbents, etc., that is detrimental to the broad objectives of sustainability and the long-term social and environmental well-being in the country. Specifically, this subsection considers the necessary policy instruments, legal and regulatory frameworks, and institutional frameworks to safeguard suitably good practice in IRP preparation.

Two global trends that have been gaining ground since the 1990s—the emergence of energy markets and international responses to global warming and climate change—require modifications to planning and management approaches to assist with setting policies and objectives, whilst increasingly allowing market-based instruments to achieve these objectives.

Most countries in the international community have recently made commitments to reduce GHG emissions relative to a BAU scenario. Preparing the targets on GHG emission reductions has required consideration of various economic sectors, in addition to electricity generation and end use, which can include industry, agriculture, or transportation. Consequently, each line ministry needs policies and plans to achieve their targets. Over arching frameworks are also needed to coordinate the plans and to ensure cooperation between agencies.

Within the power sector itself, the vertically integrated, state-owned monopolies that existed a few decades ago have often been replaced by legacy utilities, IPPs, regulators, transmission system operators, or market operators.

Policy Instruments to Achieve IRP Objectives

Generally, "Policy instruments are interventions made by government/public authorities in local, national or international economies which are intended to achieve outcomes which conform to the objectives of public policy. They can take many forms, ranging from regulatory régimes to the provision of services to help improve the performance of businesses."[28]

---

[28] C. Saublens. *Policy instruments.* KNOW-HUB. http://know-hub.eu/knowledge-base/videos/policy-instruments.html.

Well-designed policy instruments help nations attain the policy objectives underpinning an IRP.

There are various forms of policy instruments used by nations to support behavioral change toward sustainability. The range of instruments encompasses varying degrees of public intervention: regulatory instruments are at the most intense end of the spectrum, educative and voluntary instruments are at the least-intensive end, and economic incentives and disincentives are somewhere in the middle.[29] Instruments across this spectrum are used to influence behavior in ways that are consistent with the broad aims of IRP preparation, e.g., to promote EE&C investments and both large- and small-scale renewable energy projects. Of specific interest in this subsection, however, are the policy instruments designed to ensure that power expansion planning is undertaken in a manner consistent with good practice IRP.

A well-functioning power sector is of considerable strategic interest to most other sectors in a nation's economy. Accordingly, the IRP must be integrated with the plans prepared for other key sectors, such as manufacturing; oil, gas, and coal mining; agriculture; transportation; and social welfare. Through cooperation across the various sectors, policy instruments have a greater prospect of satisfying objectives across multiple sectors, rather than being in conflict. Early consultations with other ministries provide the best opportunity for aligning the IRP with other sector plans. To meet the needs of IRP objectives that potentially conflict with those of other sectors, South Africa adopted multi-objective decision-making criteria to meet three critically important cross-sector objectives.[30]

Some GMS countries have long-established policies covering energy sustainability (e.g., green growth policy strategies) that are not followed up with the necessary legal and regulatory frameworks, institutional capacity, and financial resources to achieve the aims of those policy instruments.[31]

The Government of the UK provided an example of good practice by publishing its policy on UK energy security during 2010–2015, setting down the planned actions to meet the objectives of ensuring that the country has adequate capacity and is both diverse and reliable.[32] This energy plan is consistent with the government's broader planning frameworks for nationally significant infrastructure. The document also cross-references specific ongoing initiatives and pilots, together with planned interventions, to meet the government's objectives. The policy was only finalized after a consultation process that accorded with published guidelines.

---

29 ejolt. *Policy instruments for sustainability.* http://www.ejolt.org/2012/11/policy-instruments-for-sustainability/.

30 S. Dixit et al. 2014. *10 Questions to Ask about Integrated Resource Planning.* World Resources Institute (WRI). USA.

31 ADB. *Gap Analysis Report: Integrated Resource Planning with Strategic Environmental Assessment in the GMS.*

32 Government of the United Kingdom, Department of Energy and Climate Change. 2015. *2010 to 2015 government policy: UK energy security*. UK. https://www.gov.uk/government/publications/2010-to-2015-government-policy-uk-energy-security/2010-to-2015-government-policy-uk-energy-security.

Legal, Regulatory, and Institutional Frameworks

Examples of policy instruments for IRP can be found in South Africa, several US states, Viet Nam, and elsewhere. Constitutional arrangements, legal systems, and government structures vary markedly from country to country, which makes it difficult to draw detailed recommendations for other countries. In some countries, for example, regulatory commissions at the national level mandate that utilities prepare electricity plans, which may or not be defined as IRPs. In other countries, responsibility for preparing electricity plans is assigned to national or regional planning agencies.

The spectrum of policy instruments through which IRPs may be undertaken includes mandatory measures such as laws and regulations, policies and directives, interlinking of departments and/or programs through funding arrangements, pricing and financial mechanisms, designated staff with a specific focus, capacity building, standards, and encouragement of public participation.

IRP rules in US states have been established in various ways. In 2010, D'Sa found that 23 of the 31 US states practicing IRP have laws requiring them.[33] While in some states the legislatures have passed bills mandating utilities to undertake resource planning, other states have codified IRP rules under their state administrative code. The utility commissions in some states have adopted IRP regulations within their administrative rules or have required IRP through docketed proceedings. Combinations of approaches have also been used.[34]

South Africa also has legally mandated IRPs for more than a decade. In that country, the Electricity Regulatory Act, 2006, in addition to mandating that IRPs be undertaken, assigns responsibility for electricity planning to the energy minister (footnote 18).

D'Sa found that utilities in many US states are required by law to include within their IRP various types of risk analyses (e.g., fuel price risk). Several US states, predominantly in the west of the US, require, by law, their utilities to consider GHG emissions in the IRP.

In the GMS, Viet Nam provides a good example of how almost every aspect of IRP preparation, from assigned responsibilities through to the detailed content of the IRP, is defined in the legislation, typically through Prime Ministerial Decisions. Details of the Vietnamese processes are provided in chapter 4.

Regulatory and institutional frameworks are often based on legacy arrangements, but international evidence suggests that they are more readily modified than a nation's constitutional arrangements or legal systems. Many countries around the world have modified their regulatory arrangements and institutions impinging on the power sector to adjust to a deregulated and liberalized industry with significant levels of

---

33 International Energy Initiative. 2011. *Integrated Resource Planning; Part 2: Options for the implementation of an Integrated Resource Planning (IRP) process in the Indian electricity sector*. Bangalore. Also see footnote 14.

34 The number of US States requiring IRPs has subsequently risen to 34.

private sector participation. Research conducted by D'Sa found that identifying suitable policy agents to undertake IRP preparation would depend on how integrated the IRP planning was required to be; ranging from a comprehensive consideration of supply and demand options at the national level, through to partial consideration of some alternatives in local jurisdictions. After considering potentially feasible institutional frameworks for India, D'Sa proposed the following:

(i) at the national level:
  (a) the Planning Commission,
  (b) appointees of the Central Electricity Regulatory Commission,
  (c) the Central Electricity Authority, through its IRP division, and
  (d) a new working group comprising members from the concerned ministries and departments, and other experts; and

(ii) at the regional level (i.e., state or utility):
  (a) appointees of the State Electricity Regulatory Commission,
  (b) the state's planning departments, and
  (c) individual utilities (i.e., generators and distributors) (footnote 14).

These recommendations reflect two key considerations. First, devolved responsibilities to regions, which aligns with those in some GMS countries to devolve licensing authority for generation facilities up to 15 MW or 30 MW, for example. Second, in the interests of pan-ministry coordination on issues such as national objectives, the frameworks include both the national planning commission and a working group that draws members from concerned ministries. Such coordination not only conforms to good governance but also makes the planning process more efficient (footnote 30).

3 Key Technical Themes in Integrated Resource Planning

3.1 Energy Efficiency

Electricity prices in the GMS countries are, in many cases, still below cost-recovery levels, so it is reasonable to assume that further above-inflation tariff increases will occur. The prevalence of historical cost accounting in South Africa—especially where older and capital-intensive hydropower projects predominate—can lead to tariffs that poorly reflect the true cost of electricity supply. Although additional energy savings may be stimulated through future price increases, it cannot be assumed that these savings will occur automatically.

Rather than stimulating greater energy efficiency, the effect of energy price increases may be to push firms into financial difficulties and reduce households' disposable income. It is therefore important that policies and measures are in place to enable and assist energy users in responding positively by undertaking energy efficiency measures in response to any future increases in energy prices. Fiscal policies will need to be established to incentivize businesses and homeowners to improve energy performance by increasing access to affordable financing for energy efficiency improvements and, ultimately, providing the overall business enabling environment for improving energy efficiency. This is important in the context of the current absence of innovative financing mechanisms that increase the feasibility and reduce the risk of implementing energy efficiency projects, thereby encouraging private investment. For countries such as Cambodia, the Lao PDR, and Myanmar, the lack of a formally adopted energy efficiency legislation and energy efficiency standards constrains the actual implementation of the energy efficiency program.

It is widely accepted that having a policy to promote energy efficiency is probably the most cost-effective option for managing energy demand. Developing and implementing a broad range of EE&C initiatives is widely considered the best route to surmount the negative impacts of energy production and consumption from various perspectives, including reliability, technical acceptability, affordability, and environmental sustainability.[35]

There is a general lack of opportunities for data exchange and systematic assessment of energy-saving policies among the GMS countries. Institutional capacities for developing

[35] N Zainudin et. al. 2016. *Low-Hanging Fruits: Impact of Socio-Economic and Behavioural Characteristics on Consumers' Willingness to Pay*. Malaysian Journal of Consumer and Family Economics. Volume 19. pp. 115-126. http://www.majcafe.com/wp-content/uploads/2017/04/8.-low-hanging-fruit-1.pdf.

and implementing national policies on energy efficiency in some of the countries are weak and require efforts to improve legislation, regulation, standardization, and other policy and institutional measures.

3.2 Renewable Energy

Overview of Best Practice in Renewable Energy

Realizing the opportunities presented by power generation from renewable energy sources (RES)—such as solar and wind—is one of the key challenges facing the power sector in most countries, including those in the GMS. Central to this is the development of an effective policy and regulatory framework that reflects an understanding that renewable energy policy needs to go beyond implementing individual policy mechanisms (e.g., a feed-in tariff) or setting a capacity target (e.g., 10,000 MW by 2025). Investors and project developers look at many other issues when deciding whether to invest and so should the governments aiming to promote renewables.

A broad enabling framework is needed that encompasses policy measures in areas broader than renewable energy policy alone, broader even than energy policy. These measures include (i) economic, tax, industrial or labor policies; (ii) environmental measures; (iii) education and skills development strategies; (iv) instruments to facilitate access to finance; or (v) conducive institutional arrangements. Importantly, all these measures need to be well coordinated, working in harmony, like gears in an engine (Figure 2). The extremely low costs of renewable energy that are observed in some countries around the world are achieved because these gears are working in full harmony. In some other countries, lack of renewable energy investment or significantly higher prices proposed by renewable energy developers (e.g., in a power purchase agreement [PPA] negotiation process) than in other similar countries, may indicate that some of these gears are not working well.

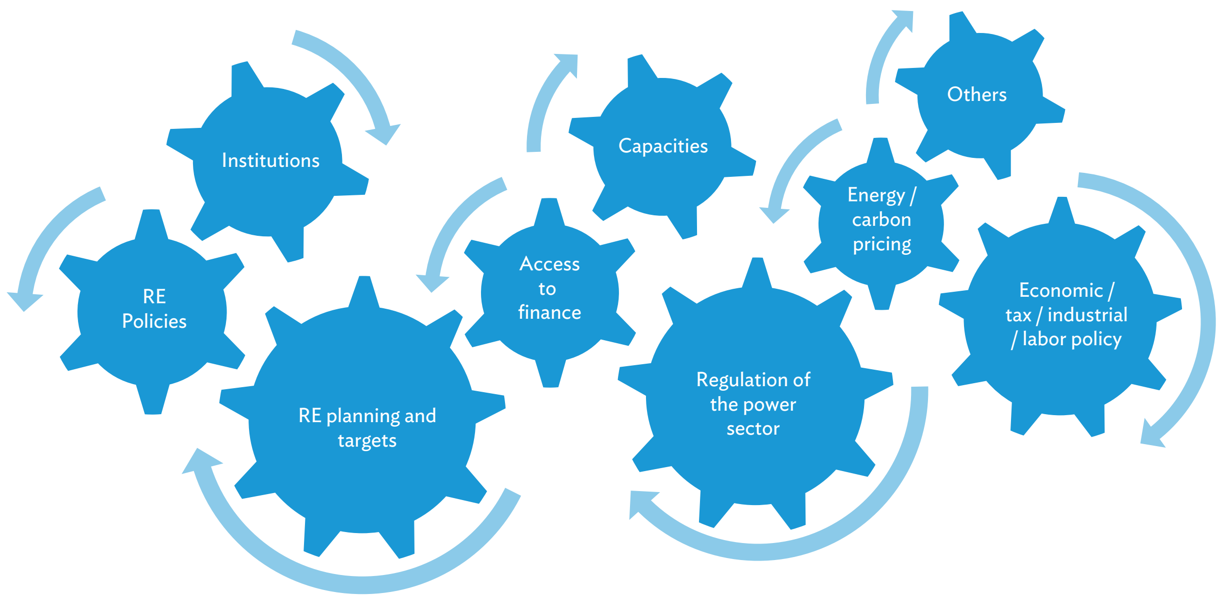
One example of best practice that reflects this integrated approach is Malaysia's 2009 National Renewable Energy Policy and Action Plan,[36] and this remains an important reference because of the way that the Government of Malaysia adopted a multifaceted approach to renewable energy expansion that went beyond simply setting a target for renewable penetration.[37] Policies were adopted to attract private investors, resulting in the significant expansion of renewable energy manufacturing. A recent International Renewable Energy Agency (IRENA) report notes that foreign direct investment has turned Malaysia into a major solar photovoltaics manufacturer for export markets. This plan aimed to implement a vision of socioeconomic development linked to renewables.[38]

[36] Government of Malaysia, Sustainable Energy Development Authority. 2009. *National Renewable Energy Policy and Action Plan*. Putrajaya, Malaysia. https://www.seda.gov.my/policies/national-renewable-energy-policy-and-action-plan-2009/.

[37] V. Anbumozhi et. al. 2016. *Investing in Low-Carbon Energy Systems*. Singapore: Springer.

[38] IRENA. *2019. Renewable Energy and Jobs – Annual Review*. Abu Dhabi.

Figure 2: **Concept of Enabling Framework for Renewable Energy**



Source: Ricardo Energy & Environment's elaboration inspired by the International Renewable Energy Agency.

Specific elements of Malaysia's action plan identified five coordinated action areas:

(i) an effective legal and regulatory framework for renewable energy,

(ii) a supportive business environment,

(iii) human capital development,

(iv) research and development enhancements in related sectors, and

(v) public awareness and renewable energy policy advocacy programs.

Renewable Energy Planning and Targets

Best practices on integrating renewable energy in power planning include the following:[39]

(i) The IRP modeling process should consider renewable energy as another possible supply technology, along with gas, coal, or hydropower. In some countries, renewable energy is fixed (e.g., to a certain percentage of total generation capacity), and its production then subtracted from demand, so that the planning tool optimizes the supply across the other (non-renewable energy) technologies

[39] IRENA. 2017. *Planning for the Renewable Future*. Abu Dhabi.

and is therefore unable to select an increase of renewable energy even if the economics of renewable energy in the overall IRP with SEA would suggest it.

(ii) Consider synergies across renewable energy technologies. In tropical countries, solar photovoltaics can operate complementarily with hydropower (across the wet and dry–wet seasons), both from a resource perspective and because solar can also facilitate investment (smaller investments and risks) and can be developed faster than hydropower in the event of fast demand growth.[40]

(iii) Use capacity credits to value the firm capacity provided by renewable energy.[41]

(iv) Use flexibility credits (which will likely be low for wind and solar, and high for hydropower and bioenergy), and use a minimum flexibility constraint to ensure that enough flexible generation is planned.

(v) Increase time and space resolution of the planning tools used, with better-calibrated time-slices to reflect renewable energy variability (e.g., include different solar production and/or capacity factors in dry versus wet seasons).

(vi) Link renewable generation planning to grid planning (e.g., adding a per unit transmission cost for each unit of variable renewable energy (VRE) capacity; or represent different generation zones, and the grids between them, in the model or tool used for planning).

(vii) For more advanced penetration levels, when measuring the costs and benefits of integrating renewables, planners should aim to evolve from using LCOE metrics to system value.

An interesting example of linking renewable energy with IRP processes is South Africa's IRP and its electricity plan to 2030, which reflects national priorities to reduce impacts on air and water resources, decarbonize the economy, and take full advantage of renewable energy potentials.[42]

After the planning process is completed, the desired renewable energy capacity and production figures should be transformed into renewable energy targets, which have a main mission to send clear signals to all stakeholders and avoid lock-in or stranded investments (e.g., coal infrastructure). Renewable energy targets (e.g., to 2040) should be connected to high-level national priorities (e.g., green growth strategies, NDCs), backed by strong political commitment, and anchored in short-term, concrete milestones (e.g., in 2025, 2030, and 2035), as in the case of the Caribbean Community and Common Market (CARICOM) in 2013 (Figure 3).[43]

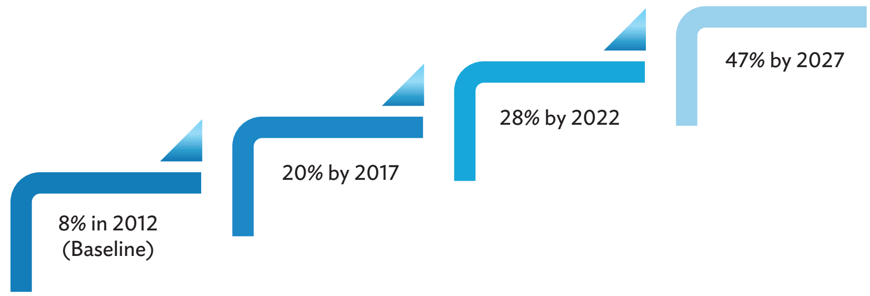
[40] IRENA. 2016. *Renewable Energy Market Analysis: Latin America*. Abu Dhabi.

[41] Some misinformed practitioners assume—incorrectly—that the firm capacity of intermittent renewable energy is zero, and that "1 MW of renewable energy requires 1 MW of conventional generation as backup."

[42] Government of South Africa, Department of Energy. 2017. *Integrated Resource Plan for Electricity*. Pretoria.

[43] IRENA. Infographics. http://www.irena.org/newsroom/infographics?page=23.

Figure 3: CARICOM Renewable Electricity Targets—Short-Term Steps Leading to the Long-Term Target



Source: Caribbean Community and Common Market (CARICOM) (2013).

Progress in achieving these targets in the CARICOM countries is slow.[44] The main reason is that energy governance needs to be improved and the restructuring of electric utility services is often a challenge. Power market structures are therefore not always sufficiently regulated to facilitate and attract the required timely investments for a diversified and affordable energy matrix. The picture is not uniform across the CARICOM countries due to market size, power sector structure, energy resource potential, and overall energy balances. The countries share some common energy challenges, however, that explains why the penetration of renewable energy technologies has proved challenging to achieve:

(i) Many countries experience a high dependence on imported fossil fuels to meet energy demand.

(ii) In some countries, consumers continue to experience limited access to energy services.

(iii) There is a lack of quality infrastructure, partly reflecting the absence of robust codes, standards, and regulations for small renewable energy technologies.

(iv) Relatively high electricity prices represent a burden for the economy, limiting the availability of disposable income for new investments in the domestic and public sectors in the region.

Stakeholder engagement strengthens ownership and the feasibility of targets, and a good example of this is provided by the European Union (EU). The EU is also an example of how the most effective targets are those that are mandatory and legally binding, even if enforcement can be challenging. A balance is needed between ambition and realism (for which stakeholder consultation is again key). Further, when specifying renewable energy targets, an important distinction is whether they apply to total primary energy supply or to total final energy consumption, whether they are technology-specific or neutral, and whether they are defined as

[44] CARICOM stands for Caribbean Community and Common Market and is defined as an organization made up of 15 Caribbean nations to promote economic integration among members.

capacity values (gigawatt [GW]), output (gigawatt-hour [GWh]), or percentages of these. Finally, monitoring needs to be ensured through accurate, periodic data gathering.[45]

Renewable energy targets alone are insufficient; they need to be part of a broad enabling framework, accompanied by a clear strategy, and backed by specific policies and measures in a wide range of policy areas. Renewable energy policies encompass many types of measures and instruments such as feed-in tariffs (FITs) or premiums, tenders, renewable portfolio standards, or specific tax incentives. Each of these has advantages and disadvantages, and much of the renewable energy policy debate already revolves around this. What is important is that no matter which specific policy instruments are chosen, policies need to be (i) stable (avoiding retroactive changes), (ii) predictable (no costly surprises for investors), (iii) adaptable (key for economic sustainability), (iv) strong enough to send a clear signal (contrary to low FITs in certain cases), (v) consistent with other policy priorities (such as energy efficiency), and (vi) long-term and consistent in their implementation.

Some trade-offs exist among these features, but a balance can be achieved. For example, France, Germany, and the UK established a FIT with a degression mechanism based on defined deployment corridors specifying the permitted levels of annual increases in renewables capacity, to ensure that the policy adapted to the falling costs of renewable technologies while avoiding retroactivity. A simplified illustration of this concept follows.

Assuming a deployment corridor for solar photovoltaics of 200 MW/year (to achieve a long-term target of 2000 MW in 10 years), FIT reduction mechanisms could be implemented:

(i) If in a single year, more than 200 MW is built, next year's FIT for new projects is reduced by 5%.

(ii) If in a single year, 100–200 MW is built, next year's FIT is reduced by 3%.

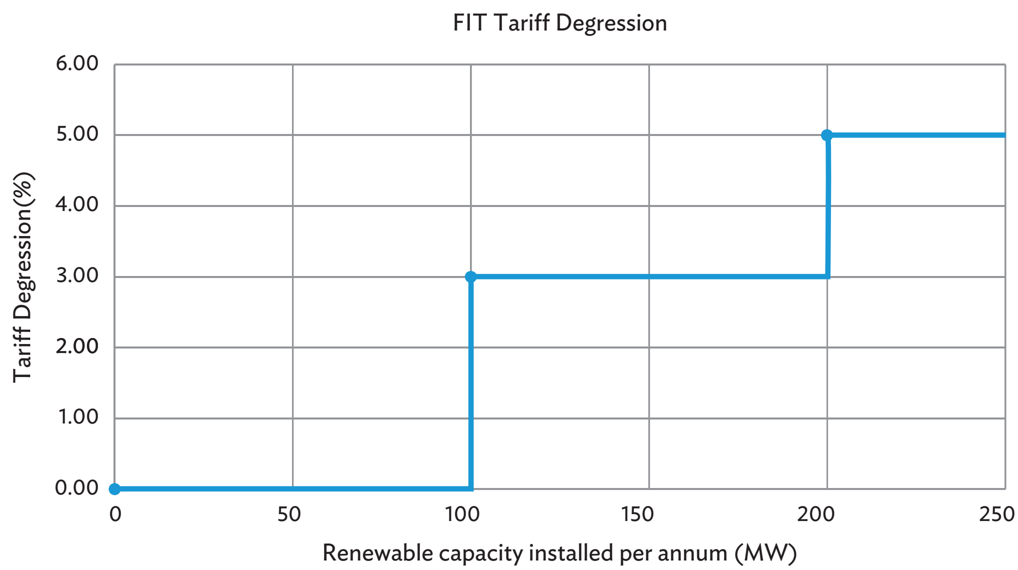
(iii) If in a single year, less than 100 MW is built, next year's FIT is not reduced. Importantly, the FIT is reduced only for new projects, avoiding retroactivity.

This concept is indicated graphically in Figure 4.

Nevertheless, renewable energy targets and policies are insufficient if the regulation of the power sector is not conducive to the development of renewables. Development of transmission and distribution grids needs to be well coordinated with renewable energy deployment, to avoid lack of evacuation potential (this has been a challenge in the PRC recently, and this topic is the subject of focused twinning activity provided by the PRC Southern Power Grid to the other GMS countries under TA 9003). Best practices in this respect include proactive grid deployment to areas of high renewable energy resource, as has been seen in Brazil, or the open season mechanisms for inviting requests for access to the transmission and distribution networks in Mexico. However, there are other concerns than simply having the grid ready for the renewable

[45] ADB. 2013. *Energy Statistics in Asia and the Pacific (1990–2009)*. Manila.

Figure 4: **Graphical Illustration of Feed-in Tariff Degression**



FIT = feed-in tariff, MW = megawatt.
Source: Ricardo Energy & Environment.

generation assets to be connected: there also needs to be a simple, streamlined, transparent, and non-discriminatory connection process, accompanied by publicly available information on connection procedures and grid capacity (if possible, at each node). In France, for instance, the available capacity at each node of the distribution network is openly available online for prospective developers to access freely.

The electricity sector should be liberalized to permit IPPs, which can bring capital, expertise, and technology. Interesting examples here include Cambodia and the Philippines. At the same time, it is of key importance to ensure that the incumbent utility has the economic incentive to allow the effective connection and electricity generation of those IPPs. Cost recovery and the overall financial viability of the incumbents need to be assured as they integrate renewables (the situation in India with local distribution utilities and solar energy provides an exemplary example).

The purchaser often buys the electricity from the renewable generators through a PPA. Such PPAs are fundamental documents that critically affect the success of the renewable energy project and its ability to raise finance. PPAs need to be attractive, transparent, and bankable. A standardized PPA template significantly reduces transaction costs and uncertainties and makes it easier for financiers and banks to consider the provision of finance for a project. The counterpart for the PPA (i.e., the off-taker) needs to be a reliable, creditworthy entity and, once again, the financial health of utilities is crucial. A scheme built around renewable energy auctions in Argentina highlights an interesting example of how to use sovereign guarantees as risk mitigation in case of off-takers failing with their payments to renewable energy generators. These sovereign guarantees (from the Government of Argentina) are, in turn, backed by the World Bank (reducing the possible risk on Argentina's finance and further increasing certainty for investors).[46]

A widely debated issue is the need for flexibility in the power sector to incorporate VRE. Indeed, such flexibility is advisable and is not as complex as it may seem. Analysis by the International Energy Agency shows how—if the share of variable renewables in the total generation mix is less than approximately 10%—there is limited need for significant network modifications since VRE can be easily integrated into most systems—unless they are extremely inflexible or isolated—because these systems are already able to cope with the variability of demand, larger than that of a few percentage points of VRE capacity.[47] In countries with virtually zero wind and solar grid-connected generation, a significant amount of VRE can be integrated before flexibility becomes a concern. More flexibility is needed if VRE is above approximately 10%—normally on the supply side. This can be easily, cost-efficiently, and reliably achieved through hydropower, gas-based generators, or bioenergy-based power generation. The cases of Brazil, Nordic countries, or Spain show how hydropower can be used to balance wind and solar production. With higher levels of VRE in total generation, storage could be used to provide a source of flexibility. Hydropower often represents a more reliable and cost-effective source of storage than batteries, which is highly relevant given the developed nature of hydropower in the GMS countries, and which will continue to be an important part of the generation mix.

Once the share of VRE in total generation goes beyond 20%, dedicated flexible backup power generation and demand-side flexibility (e.g., smart grids and demand-side management, smart electric vehicle charging) start to become important. The renewable deployment also needs to be system-friendly through measures such as allowing or mandating VRE to provide system services and be remunerated for them (capacity, balancing, ancillary services, etc.); giving locational signals to their deployment (e.g., through specific remuneration schemes); ensuring that they respond to scarcity signals (e.g., exposure to market prices); and integrating a diversified portfolio of technologies. Adaptation of electricity dispatcher markets will probably also be needed.[48] No matter what the level of VRE, making the market larger and more interconnected (e.g., to other areas or to neighboring countries), is always advisable. Subsection 3.3 considers in some detail the complexities of integrating renewable into transmission system operation and development.

The previous paragraph raises examples of where the disruptive technologies—coupled with liberalized and deregulated power markets, innovative entrepreneurs, e-commerce, or venture capital—are creating commercial opportunities that lubricate the drive toward meeting GHG reduction targets. Examples of this are

---

[46] Renewables Now. 2018. *2018 Argentina Renewable Energy Report*. Buenos Aires. https://www.filepicker.io/api/file/sWObLMBQS6C46ms7L1Bi.

[47] International Energy Agency. 2018. *System Integration of Renewables: an update on best practice*. Paris. https://www.iea.org/reports/system-integration-of-renewables.

[48] IRENA. 2017. *Adapting Market Design*. Abu Dhabi.

emerging rapidly in Australia, Northern Europe, and the US. A side effect of this trend, however, is the risk of those legacy utilities rooted in conventional thermal generation technologies being outcompeted and burdened with stranded assets.

Access to Key Information

Public information for developers is key to knowing where opportunities for new projects may lie. This is a win–win for both developers—for whom lack of information can be a critical barrier—and for policy makers, i.e., to know where renewable energy will most likely be developed and to enable the planning of the grid accordingly. A dedicated government agency could be set up, responsible for publishing online open, public, transparent, and up-to-date information on aspects such as

(i) renewable energy resource assessment data;

(ii) grid infrastructure, e.g., constraints, capacity, planned and/or existing lines and substations;

(iii) electricity supply, demand, and prices;

(iv) renewable energy project pipelines;

(v) land use, tenure, conservation, roads, etc.;

(vi) financing options; or

(vii) policies, standards, institutions, and procedures.

Availability and Cost of Finance

In a capital-intensive industry such as renewable energy, the availability and cost of finance (both debt and equity) are fundamental. A first measure to ease access to finance includes improving project readiness and attractiveness. This can be achieved by (i) using project facilitation tools such as Project Navigator by IRENA, (ii) engaging in tutoring programs (e.g., Private Financing Advisory Network PFAN by UNIDO), (iii) using public resources to provide bridge finance early in the projects, or (iv) setting up blended finance and/or PPP schemes (e.g., Leading Asia's Private Sector Infrastructure Fund LEAP by ADB and JICA).

A second measure could be facilitating access to local financing, for which tools could include increasing the capacity of local banks (e.g., training staff) and implementing on-lending structures to channel funds.

A third measure could be introducing risk mitigation measures, such as guarantees or subordinated risk instruments. A good example of this is the sovereign and World Bank guarantees set up in Argentina. Other ways of reducing risk include streamlining application processes, standardizing credit enhancements, and bundling small projects. A fourth measure could include setting up or enhancing national financing vehicles (e.g., green investment banks) and, eventually, tapping into capital markets (e.g., green bonds in Singapore).

Energy Pricing, Climate, and Environmental Policies

Energy pricing, climate, and environmental policies play a key role in ensuring competitiveness for renewables. Low electricity prices can be problematic since they reduce profitability for renewable energy projects as well as weakening energy efficiency efforts. As such, electricity prices should be fully cost-reflective, including external costs (e.g., the pricing of carbon and other pollutants, and maybe even including the opportunity cost of water used for hydropower). To consider vulnerable consumers, an option is to use a rising-block tariff—such as those in India or Indonesia—which considers not only energy but also maximum demand. Beyond electricity pricing alone, other energy pricing interventions could provide equal opportunity for renewables. These include reforming fossil fuel subsidies and reducing interventions that favor conventional generation directly or indirectly (e.g., certain tax structure and/or exemptions, coverage of nuclear risks, government participation in oil and gas extraction). Recent initiatives in Indonesia and Malaysia could provide some useful insights. Predictability and transparency in future electricity tariff setting are important for investor certainty.

Other Policies and Measures

Other policies and measures beyond energy are also key. These include economic and tax policies, supply chain, awareness, and others. If private investment is to be attracted, improving the overall business and investment environment in a country is fundamental. The World Bank's Ease of Doing Business indicators and reports can provide useful reference.[49] As part of this, country and currency risks should be mitigated to the greatest extent possible; for example, many renewable energy projects face significant currency risks, with their costs being in US dollars and incomes in local currencies. Tax exemptions could be granted on some equipment imports (e.g., those that cannot be sourced locally), or on some corporations (e.g., small IPPs). Social protection policies could be needed to address transformation in affected areas (e.g., coal mining regions). These could be linked to labor market needs such as flexibility measures to support the transferability of workers or retraining programs.

It is important to ensure the reliability of technology for supply chains for renewable energy—for example by adopting regional and/or global quality and technical standards such as those set by the International Organization for Standardization or the International Electrotechnical Commission, or by ensuring certification of installers and operators. Low-quality technology can undermine trust and threaten integration in the power grid. Local supply chains need to be encouraged or reinforced, ensuring that the installers, maintenance, and other required goods and services are available. Feedstock supply is critical for bioenergy, where sustainability and non-interference with food security are of critical importance. The development of a local renewable

---

[49] World Bank. *World Bank Open Data.* https://data.worldbank.org/indicator/IC.BUS.EASE.XQ.

energy industry could be considered, but only after a careful cost–benefit analysis involving wide stakeholder consultation, since the price to quality ratio of imports could be better. If supporting such a local industry is desired, this can be undertaken using industrial policy measures (e.g., leveraging existing local capacity and synergistic industries such as semiconductor, metals, or construction, providing premiums in support mechanisms based on levels of local content, or setting caps in foreign participation in auctions), or trade policy measures (e.g., trade agreements, export promotion). Lastly, awareness programs are needed to increase public knowledge and/or acceptance of renewable energy and induce behavioral change.

Institutional Setting

Another key aspect—beyond the specific policies and measures mentioned above—is the institutional setting. A high-level, national vision for the role of renewable energy in the future of the country—including the economy, development, green growth, and NDC implementation—linked to energy planning and targets, can send a strong signal to all stakeholders. Critically, this allows all institutions to progress in the same direction, ensuring policy coordination between competencies and across national and local levels. It is fundamental to have well-defined roles and responsibilities, information sharing, streamlined procedures, and the avoidance of duplications and conflicts. Trustworthy, transparent institutions and procedures can greatly increase the attractiveness of the country for renewable energy investors, and dedicated measures can be introduced to reduce incumbents' resistance to renewable energy, which is often channeled through lobbying.

Dedicated Agency for Renewable Energy

A dedicated renewable energy agency—ideally within a national energy institution such as a ministry of energy—is beneficial to ensure coordination across all aspects of the enabling framework described above. Such an agency could act as the key provider in charge of easing clearances, permits, and other administrative requirements for renewable energy developers. Critically, the agency should streamline land acquisition and permitting and make it simple, fast, predictable, transparent, and—if possible—inexpensive. If land availability is an issue, shared use of land could be an option (such as floating solar photovoltaics in the PRC), farming and ranching between wind turbines, or dual agriculture and renewable energy use of land (e.g., solar sharing in Japan). Finally, the renewable energy agency, or some other department, should oversee the collection, maintenance, and provision of open access to good quality RES data and statistics as a prerequisite for solid policy making and informed decision making by all stakeholders.

Capacity Building and Skills Development

Capacity building and skills development are key elements of successful renewable energy development. Several studies have warned about the skills gap in the renewable energy subsector across the world, and how it can be a significant barrier to growth in the industry. As a first step, a diagnosis could be undertaken through a skills need assessment, as part of the renewable energy planning process. Specific measures could then be put in place, in coordination with education and labor policy. Malaysia's National Renewable Energy Policy and Action Plan is an interesting example (footnote 36). It included measures for education and training that incorporated renewable energy into tertiary and technical educational curricula, developed centers of excellence and training institutes, and provided dedicated financial support.

Conclusions on Best Practice in Renewable Energy

In conclusion, a wide-ranging set of measures is needed to create an effective enabling environment for renewable energy. These go well beyond what traditionally has been considered as renewable energy policy. These measures should all be coordinated and need to work in harmony, as with the example of the gears in the mechanism shown in Figure 2.

Integrating Renewable Energy into Transmission System Operation and Development

Subsection 3.2 observed that—according to analysis undertaken by the International Energy Agency—if the share of variable renewables in the total generation mix is less than approximately 10%, there is limited need for significant network modifications. Before the limit is reached, however, measures are necessary to prepare the transmission and the distribution networks to successfully accommodate such amounts of renewable energy integration. In best practice, these measures should be taken in the regulatory field (connection codes, connection procedures, and charging rules), the planning field (network development studies and their methodology), and in the operational field (real-time visibility, generation forecasting tool, reserve procurement).

Policies for Integrating Renewable Energy

According to international best practice, countries typically take the following specific measures to adapt their power sector to accommodate the integration of a significant quantity of renewable energy without jeopardizing network operation. These measures mainly consist of

(i) adapting connection codes, introducing high-level technical requirements for all types of renewable energy;

(ii) establishing transparent and non-discriminatory rules for connection charging;

(iii) anticipating network investments for renewable energy connections;

(iv) adapting the methodology for long-term adequacy studies and transmission development planning;

(v) implementing real-time visibility and accurate forecasting for intermittent and decentralized energy sources; and

(vi) adapting power markets and reserve markets.

Some of these measures need to be implemented from the initial stages of enabling renewable energy connection, particularly those related to the regulatory procedures (grid codes, connection procedure). All other measures need to be implemented when intermittent and decentralized generation reaches a significant proportion of the generation mix.

Connection Codes and Procedures

Public connection codes—especially connection requirements—are of the utmost importance for establishing a transparent and equitable framework for production investment. They also set the technical requirements for generating units necessary to maintain a high level of security during future network operation. A lack of these technical requirements can jeopardize network operation and act as a deterrent to investors. While preparing or revising these procedures and rules, the authority in charge of this task needs to conduct an extensive and early consultation process involving all stakeholders.

Connection codes have already been published in most of the GMS countries, but the majority of these do not contain any provision regarding solar and photovoltaic generating units. Even the Viet Nam connection codes—which are the most exhaustive in the region—need to be extended to facilitate the integration of a significant number of small-scale photovoltaic panels. Moreover, these national codes need to be harmonized for ensuring the compatibility of the technical requirements with those of neighboring countries. In the GMS context, the international references that can be used for benchmarking connection codes are as follows:

(i) requirements of the GMS connection code (Performance Standards and Regional Grid Code) recently drafted by RPTCC; and

(ii) requirements of the European network codes (Network Code on Requirements for Grid Connection of Generators EU 2016/631), which is a particularly useful reference because this code has been designed to accommodate rapid and substantial renewable energy growth.

Another good practice that can be adopted from international experience consists of conducting an extensive consultation process while preparing or revising the connection codes. In Europe, Regulation No 714/2009 of 13 July 2009—Regulation on Conditions for Access to the Network for Cross-border Exchanges in Electricity—makes this consultation process mandatory.[50] The authority responsible for undertaking this task needs to "conduct an extensive consultation process, at an early stage and in an open and transparent manner, involving all relevant market participants, and, in particular, the organisations representing all stakeholders" (footnote 50).

[50] European Parliament. 2009. *Regulation (EC) No 714/2009 of the European Parliament and of the Council*. Brussels. https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF.

Anticipated Network Investments for RES Connection

The time taken to plan and build new substations and transmission lines—which is very often more than 5 years—is generally longer than the time needed to construct renewable energy facilities (typically 2–3 years), which poses an obstacle to renewable energy development. Measures must be taken to formulate the network in advance, to facilitate renewable energy integration. In France, for example, administrative authorities have implemented regional development plans for renewable energy connection enabling them to

(i) increase capacity to connect renewable energy to the grid with limited new assets,

(ii) provide visibility of the location of planned developments and reinforcements,

(iii) make grid developments in advance to facilitate renewable energy development, and

(iv) distribute the costs of grid development evenly between renewable energy investors.

These regional development plans rely on a percentage of the available connection capacity at certain network nodes being reserved for new renewable energy integration over 10 years, where this capacity is not available for other means of generation.

Adapted Transmission Planning Methodology

Countries that rely on a significant amount of RES—or which are introducing the unbundling and decentralized market processes in their power sector—are facing increasing difficulties in developing their long-term network plans due to increasing uncertainties over the future power system. Among these problems, the most concerning are the lack of a clear vision for the future generation mix (partly based on private investments), future fuel and investment costs, and the difficulties of identifying the most severe situations for the transmission system considering the uncertainties of the production output of intermittent energy sources. The standard least-cost optimization method needs to be adapted to provide more robust results in such an uncertain environment. Different scenarios need to be studied to describe an envelope of the various possible futures and specific criteria for addressing uncertainties. Techniques such as the minimax regret criterion may be used for determining the optimum decision when least-cost optimization leads to significantly different recommended solutions between one scenario and another.

When the installed capacity of intermittent renewable energy reaches a certain level, the standard deterministic approach is no longer suitable for establishing a long-term development plan. Critical situations on the network can occur in periods quite different from those studied within the framework of the deterministic approach (mainly peak load and minimum load situations), for example, in instances of high- or low-intermittent production. A probabilistic approach is consequently needed to explore all possible eventualities, allocating a probability of occurrence to each of them. This approach implies that it is necessary to study the network conditions, not only during few typical situations such as those considered under the deterministic approach but throughout the year, combining uncertainties on the availability of generation plants, demand, wind or sun conditions (which determine the generation output for intermittent generation), etc.

Real-Time Visibility and Accurate Forecasting for Intermittent and Decentralized Energy Sources

With the integration of new renewable energy capacities into the power system, the system operator will face increasing levels of unpredictability in the generation forecast. Without specific measures, an increase in the operating reserve will be needed to face these new uncertainties. The experience of European countries shows that real-time visibility and accurate forecasting for intermittent and decentralized energy sources enable the mitigation of this problem and the maintenance of the reserves needed to operate the system at a stable level.

In the European network codes, the capability for exchanging information with the system operator (in real-time, or periodically with timestamping) is required for power generating modules >1MW (in continental Europe).[51]

Generation forecasting services are now provided by international specialized companies at low costs. Another solution for countries could be the implementation—in the load dispatcher center—of a specific IT platform with in-house adapted products such as those developed in Spain (the Centro de Control de Renovables—CECRE—a dedicated renewable energy control center) or in France (the IPES platform). The high costs of these solutions could be considered only when the previous forecasting services are insufficiently accurate for the safe operation of the network.

Adapted Reserve Procurement

Reserve procurement is becoming progressively more difficult and costlier than conventional generation—which has traditionally provided this service—is displaced by renewable energy generation. There are two main ways to allow better flexibility in reserve procurement. The first consists of introducing new reserve suppliers on the demand side or based on storage facilities (e.g., batteries). The second is based on expanding the markets—for example on a regional scale—to attract more bidders and to be able to select the most desirable propositions in terms of cost or time of activation. In terms of reserve requirements, the most common international standards for reserve sizing are as follows:

(i) the primary reserve must be greater than the largest facility connected to the grid (generating or consumption facility, high voltage direct current [HVDC] system); and

51 entsoe. *Requirements for generators.* https://www.entsoe.eu/network_codes/rfg/.

(ii) the frequency restoration reserve, for which full activation time is less than 15 minutes—be it automatic (secondary reserve or automatic generation control) or manual (mainly fast-acting hydropower reserve or gas turbines)—must also be greater than the largest facility in the area controlled by the load dispatch center.

From European experience, these rules are reliable enough to guarantee operational security, even with a high rate of penetration of renewable energy (with the prerequisite that each load dispatch center is equipped with real-time monitoring and RES generation forecasting).

Reserve is traditionally provided by conventional generating units (i.e., thermal and hydropower plants). The procurement can be based on technical requirements—for example, each unit is required to provide a minimum percentage of its rated power to the primary reserve while generating—or on a market-based process (e.g., through a single-buyer market for purchasing the necessary amount of reserve).

Cross-Border Interconnection and Power Trade

Cross-border interconnections are generally complex enterprises, requiring careful consideration across several disciplines: technical, economic, legal, political, social, and environmental.[52]

Technical Considerations of Cross-Border Interconnections

Key technical issues include

(i) whether the interconnected systems are to operate synchronously or asynchronously;

(ii) volume and direction of energy flows;

(iii) distances and physical geography (such as mountains or rivers) to be spanned; and

(iv) relative characteristics of the power systems being connected, e.g., predominantly thermal, predominantly seasonal hydropower, etc.

When designing or operating an alternating current interconnection, constraints may apply to the physical interconnection and/or the grids being interconnected, such as thermal limits, stability limits, and voltage regulation. These constraints may be more onerous where one or other of the systems has a liberalized market since there are financial incentives to operate closer to capacity. When planning and assessing the benefits of an interconnection, therefore, it is extremely advantageous

[52] United Nations Secretariat, Department of Economic and Social Affairs. 2006. *Multi-Dimensional Issues in International Electric Power Grid Interconnections*. New York.

for planners to apply simulation software, but this requires considerable data from both systems.

Technical planning for interconnections needs to be coordinated, at all stages, with the other key aspects: economic, organizational, legal, and political. Bodies such as the RPTCC can help to ensure that common understanding is reached on many of the key technical considerations.

Economic and Financial Considerations of Cross-Border Interconnections

As with other elements of an IRP, grid interconnections will have direct and indirect costs and benefits. One of the principal direct economic benefits of an interconnection—to the recipient system—is the avoided costs that it delivers. These are direct life cycle costs avoided by receiving power through the interconnection, rather than by generating and distributing that energy through domestic facilities. For the sender, there is a direct economic and financial benefit from the sale of energy to the recipient. Although most of the interconnections in the GMS have been developed as uni-directional export projects, internationally there are a great many instances where an interconnection operates bi-directionally, i.e., with two-way trade between the two systems. For example, a predominantly thermal system might export power to a predominantly hydropower system during the dry season and importing surplus power during the wet season. In such cases, the trade-in each season has benefits for both parties.

Indirect benefits of interconnections may include (i) employment creation for construction and operation, (ii) improved power supplies—either to new or existing customers (as would apply to a new domestic generation project), or (iii) reduced tariffs to end users.

The pricing arrangements for power trade are extremely important. In addition to the tariffs for physical energy flows, other services—such as ancillary services—may also be provided, and thus require a pricing arrangement. Typically, prices can be based on production costs, avoided costs, negotiation, and market-based pricing.

Historically, there have been instances of non-transactional matched trading between two systems, with the volumes of seasonal energy flows being balanced over an annual cycle, and with no charges been made by either party.

It is increasingly common for the grid in one country to be the intermediary for cross-border trade between two—or more—other countries. The intermediary is said to be wheeling power, rather than consuming that power. In return for the use of its transmission network, the utility wheeling the power receives a wheeling charge that—usually—takes account of the volume of energy transmitted, the life cycle costs of the transmission infrastructure used for the wheeling, etc. Where the trading is through a regional power pool, such as the Southern Africa Power Pool or the West African Power Pool, wheeling charges are typically predetermined and administered by the power pool. A power pool for the GMS countries is a longer-term goal but does not yet exist. Generally, as markets become increasingly deregulated and liberalized, wheeling becomes an increasingly important consideration.

Legal Considerations of Cross-Border Interconnections

The legal considerations attached to interconnections can be very complex, although they may be ameliorated to some extent when undertaken within the umbrella frameworks of organizations such as the ASEAN and the RPTCC. The legal agreement between two countries—the interconnection agreement—should be legally binding and enforceable. The negotiation process leading to that agreement should also be transparent.

In the GMS, it is increasingly common for generation projects—often hydropower projects—in one country to export most, or more typically all, of their power output to a utility in a second country. The transmission infrastructure for that export is often owned by the IPP entity that owns the generation facility. In such cases, transmission issues are bundled together with the security package and PPA for the generation facility. In other instances, the IPP will be required to strike deals with the transmission utilities on either side of the border. Such deals will typically include the necessity to comply with the grid codes in each country and to pay some form of transmission use of system charges in each country.

Political Considerations of Cross-Border Interconnections

There is widespread recognition—not least from countries themselves—that neighboring countries with a good trading relationship will be more likely to avoid conflicts. This is one reason why the IFIs are very keen to promote interconnections, where they also make good economic sense. For a project to be considered good, however, it is not unreasonable to expect that there is an equitable sharing of costs and benefits and that no groups are being exploited for the advantage of others. Consequently, the complex legal agreements mentioned in the previous subsection must be underpinned by sound political agreements between the countries. These political agreements will cover the sharing of costs and benefits, payments to contractors, operation and maintenance responsibilities, the sharing of information pertinent to the planning and secure operation of the interconnection, and governance over the interconnection operator.

Broadly, ASEAN provides a foundation for political agreements across most of the GMS.

Social and Environmental Considerations of Cross-Border Interconnections

As noted in the previous subsection, a range of social benefits can result from cross-border interconnections. However, several social costs can also result from the construction and operation of an interconnector. Planners considering a new interconnector—and those preparing an IRP that includes candidate interconnectors—should carefully evaluate and assess these externalities. Environmental costs and benefits should also be considered carefully.

3.3 Internalization of Externalities

In 2011, a thorough review by D'Sa found that: "There are relatively few cases where the comparison of both supply- and demand-side options, and their externalities, is an integral part of the evaluation process."[53]

TA 9003 has not uncovered good examples of internalizing externalities, either. The three SEAs for Vietnamese power—although well intentioned—appear to have been insufficiently resourced to rectify this issue in detail. Although the approach adopted for Revised PDP VII led to increased renewable energy capacity and reduced coal-fired generation capacity, a more rigorous approach to the internalization of externalities would probably have produced an expansion plan with even greater penetration of renewable energy and energy efficiency.

The first challenge with this issue is quantifying the impact. If, for example, a hydropower reservoir will impact endangered species—flora and fauna—the next question is how many species and to what extent will endangerment to those species be intensified. After that, the issue is—ideally—how to monetize those impacts. Each externality typically has several different approaches to the monetization of external costs and, these approaches often produce values that vary widely. To correct this, governments, regulators, IFIs, etc., instruct planners to use a specific approach or a specific value. For example, an IFI may instruct consultants to use a certain value (e.g., \$25/tCO_2e) for GHG emissions. Other solutions advocated to address the issue of externalities include environmental regulations, pollution quotas—such as tradeable emission permits and taxes and tariffs on pollution. The question for governments considering these approaches, however, is whether the standard of governance in the country is high enough to control them.

Economists have recognized the concept of externalities for over 100 years and occasionally incorporated these into cost–benefit studies where resettlement or pollution has been a key consideration. For routine PDPs, planners have often avoided the problematic issues of methodologies and valuations for externalities. Nevertheless, there has been renewed interest in valuing externalities with the narrowing of the relative costs of renewable energy generation versus the more polluting conventional generation sources.

South Africa's Energy Research Centre reviewed numerous published studies on the external costs of electricity generation technologies, for use as an input to the

53 Footnotes 14 and 33. This paper presents a useful forensic review of international practices on IRP, the findings of which are still highly relevant.

Integrated Resource Plan 2 (IRP2) in South Africa.[54] This review considered a wide range of generation sources: coal, nuclear, gas–CCGT, diesel–open cycle gas turbine, biomass (including biogas), hydropower (small), wind, concentrated solar power, and photovoltaics. For each generation source, the review assessed the costs—in US cents/kWh terms—in the following categories: acid mine drainage (only for coal), biodiversity loss, health impacts, and GHG emissions. The researchers suggested that—in the modeling for South Africa's IRP2—the values should be used as externality adders, i.e., added to the costs of the various power plants. To be consistent, external costs must be added to the base case or modeler's reference case and all policy cases or scenarios. The researchers added that—for the multicriteria decision-making process—the external costs should be reported as a distinct criterion, and that the weighting of this criterion relative to others (e.g., cost, carbon, and access) ought to be raised with stakeholders—which supports the review of best practice in stakeholder consultations summarized in previous subsections.[55]

In the US, the Arizona Public Service takes environmental costs into account when evaluating its resource plans. They use adders for CO_2, SO_2, NOx, particulate matter, and water consumption.

In 2009, the European Commission supported the New Energy Externalities Developments for Sustainability (NEEDS) with a project aiming to identify quantifiable external costs related to the operation of various electricity generation technologies, whilst taking account of uncertainties in both the quantification of external costs and the specification of long-term future technology configurations.[56] Researchers in Portugal[57] have extracted externality values for power generation technologies[58] from NEEDS 2009, ExternE 2005,[59] CASES 2008,[60] and Anil Markandya 2012.[61] Their study aimed to identify the externalities of various renewable energy technologies from several studies, together with the benefits and the costs of these.

In conclusion, although D'Sa and TA 9003 have found few examples of power planners internalizing monetary values into the analysis for PDPs—with some notable exceptions in South Africa and some US states—there would appear to be appreciable information and data on the subject from academic sources.

54 M. Edkins et al. 2010. *External cost of electricity generation: Contribution to the Integrated Resource Plan 2 for Electricity*. South Africa.

55 Despite this study for South Africa, the 2018 IRP (and presumably earlier IRPs) does not include values for acidification of groundwater from coal mining nor does it place a value on CO_2 emissions. IRP 2018 says that it does not include the external costs of carbon emissions because "the CO_2 emissions constraint imposed during the technical modeling indirectly imposes the costs to CO_2 from electricity generation." In other words, they put a limit on how much CO_2 can be emitted instead of costing the climate damage from burning coal to generate electricity. EGAT in Thailand adopts the same approach for their PDPs.

56 New Energy Externalities Developments for Sustainability (NEEDS). 2009. *External costs from emerging electricity generation technologies*.

57 A.M. Sundaram. 2016. *Measurement of Externalities for Renewable Energy Investment*. Instituto Superior Técnico, Universidade de Lisboa. Portugal.

58 ADB. 2017. *Guidelines for the Economic Analysis of Projects*. Manila.

59 European Communities. 2005. *ExternE:Externalities of energy; methodology 2005 update*. Luxembourg.

60 CASES. 2008. D.06.1 Database of Full costs for EU, with external and private costs, Deliverables CASES. http://www.feem-project.net/cases/downloads_deliverables.php.

61 A. Markandya. 2012. *Externalities from electricity generation and renewable energy: Methodology and application in Europe and Spain*. Basque. Basque Centre for Climate Change. pp. 85–100.

4 Strategic Environmental Assessment

4.1 International Experience in Strategic Environmental Assessment

Evolution of SEA

Strategic environmental assessment (SEA) has been extant for around 30 years and has evolved due to a perception that environmental decision-making methods were—despite considerable attention—inadequately solving the challenges arising in the late 20th century. One tool for safeguarding against adverse social and environmental impacts arising from major infrastructure projects is the enviromental impact assessment (EIA)—a tool that has been almost universally adopted as a legal requirement by governments and as a funding condition by development agencies. Shortcomings identified with EIAs include:

(i) **Timing issues**. Since an EIA for a project is undertaken later in a project's development when the realization of the project's environmental shortcomings arise from failings in the underlying policies.

(ii) **Incremental factors**. Policies that are implemented incrementally through small or iterative decisions and projects may only identify critical failings in the policy at a very late stage, e.g., when multiple projects have been implemented.

(iii) **Information deficits**. Crucial environmental information may not be available when policies and strategic plans are prepared.

Support for the SEA concept developed steadily during the 1990s and an understanding evolved of the crucial benefits in applying SEAs to policies, sector strategies, development programs, road maps, national and regional plans, investment programs, etc., while EIAs could still be applied to the development projects that arise from such policies and plans.

Several bodies have advanced SEA definitions, good practice principles, criteria, etc. These have produced a high degree of commonality in their understanding of concepts, rather than unanimity in applying methodologies. During 1990–1994, SEA was being applied by countries such as Canada, Denmark, the Netherlands, New Zealand, South Africa, the UK, and the US. During the early years, however, SEA was not applied to infrastructure development—such as that for the power sector—and was more commonly applied to areas such as urban planning and land use planning.[62] The EU considered the merits of SEA for several years before introducing it for assessing the environmental impacts of certain plans and programs during 2000–2004.[63]

SEA and the Power Sector

For several years, institutions wrestled with key fundamentals of an SEA, such as objectives setting, principles, criteria, defining indicators, and how to evaluate SEAs. During 2000–2004, SEAs tended to be very high level, typically with a land use orientation. Considering that climate change and global warming were already the leading international environmental issues at that time and that the power sector—together with transportation—accounted for the vast majority of global GHG emissions, there were few—if any—SEAs for power development plans during this period.[64] There was, however, SEA activity in the GMS countries during this early period:

(i) Sida's strategy for development cooperation between Sweden and Viet Nam was accompanied by an SEA in 2002–2003.

(ii) An SEA was undertaken for the Nam Theun II hydropower project in the Lao PDR, although this was project-specific rather than for a complete sector development plan.

In 2009, the United Nations Environment Programme (UNEP) renewed promotion of the green economy movement, which some authorities credit with having boosted the application of SEAs to development plans. A draft report prepared for UNEP identifies an SEA as a key mechanism for integrating development and environment interests in pursuing a green growth strategy.[65] The principles of a green economy—sustainability, justice, healthy planet, inclusion, good governance, etc.—map very closely to those of an SEA. It would appear to be the case that, at around this time, SEAs were starting to be undertaken for major infrastructure expansion programs:

(i) In the UK, an SEA was initiated in 2008 as part of the feasibility study for generating tidal power in the River Severn estuary, guided by a stakeholder steering group.[66]

---

62 B. Dalal-Clayton and B. Sadler. 1999. *Strategic Environmental Assessment: A Rapidly Evolving Approach.* International Institute for Environment and Development Environmental Planning. Issue No. 18.

63 European Parliament. 2001. *Directive 2001/42/EC of the European Parliament and of the Council.* Brussels.

64 Iceland's electricity generation infrastructure is almost entirely drawn from RES—particularly hydropower and geothermal energy. Nevertheless, these RES are not without significant social and environmental impacts. From 1999, Iceland's National Energy Authority (Orkustofnun) started preparing a Master Plan for Hydro and Geothermal Energy Resources in Iceland. Although the first such Master Plan did not specifically adopt the term SEA, to a very great extent it was undertaken to principles that closely align with those of a SEA.

65 International Institute for Environment and Development. 2012. *The Role of Strategic Environmental Assessment in Promoting a Green Economy: Review of experience and potential.* London.

66 M. H. Clough. 2019. A bold new plan to tackle climate change ignores economic orthodoxy. *The Economist.* 7 February.

(ii) In 2009, also in the UK, the Department for Business, Energy and Industrial Strategy completed an SEA of a draft plan or program to hold further rounds of offshore leasing for wind and offshore oil and gas licensing in UK waters.[67]

(iii) In July 2009, the Government of Scotland published an SEA for its Renewables Action Plan.[68]

(iv) One of the earliest SEAs focusing on the development of large energy developments— specifically for large hydropower projects and, coincidentally, in the GMS—was undertaken by the Mekong River Commission (MRC), initiated in 2009, for the MRC Basin Development Plan.[69] The SEA focused on projects at Pak Beng, Luang Prabang, Xayaburi, Pak Lay, and Sanakham in the northern Lao PDR; Pak Chom and Ban Koum near the Thai–Lao PDR border; Phu Ngoy (formerly Lat Sua) and Don Sahong in the southern Lao PDR; and Stung Treng and Sambor in Cambodia. [70]

(v) In 2012, South Africa's Department of Energy commissioned separate SEAs for its wind and solar photovoltaic energy subsectors. The objective of these SEAs was to identify geographical areas most suitable for the rollout of wind and solar photovoltaic energy projects and upgrade of the supporting electricity grid network.

Preceding any of these SEAs, however, ADB was in the vanguard of applying SEA to the preparation of PDPs. Moreover, it did this in the GMS, where it was actively supporting regional energy cooperation, and where the Mekong River basin was not only the commonality between the six GMS nations, but the use of the Mekong water resource was also a potential source of disharmony.

With the Vietnamese 2005 Law on Environmental Protection (LEP), the integration of an SEA as an integral part of the preparation of national plans for all sectors—including PDPs—became a mandatory requirement. ADB supported the first SEA of power in Viet Nam which was the SEA of the Hydropower Master Plan, within the context of PDP VI—which was prepared after PDP VI was finalized and approved.[71] This SEA was considered successful and, drawing from lessons learned, provided a basis for the preparation of the SEA for PDP VII, where it was included as part of the plan preparation. This SEA identified the externalities associated with air pollution from the proposed coal-fired generation as the largest possible impact.

[67] UK Parliament, House of Commons Hansard. 2011. *Offshore Energy Strategic Environmental Assessment*. Written statements. 12 October.

[68] Government of Scotland. 2009. *Renewables Action Plan Strategic Environmental Assessment: Environmental Report*. Edinburgh. https://www2.gov.scot/Publications/2009/07/01093638/0.

[69] Mekong River Commission. 2010. Strategic Environmental Assessment of Hydropower on the Mekong Mainstream: Summary of the Final Report. Prepared by International Centre for Environmental Management.

[70] INTERNATIONAL Rivers. *Mekong Mainstream Dams*. https://www.internationalrivers.org/campaigns/mekong-mainstream-dams.

[71] Government of Sweden, Ministry of Industry and Trade. 2008. *Strategic Environmental Assessment of Hydropower in the context of the Power Development Plan VI in Vietnam: Final Report*. SEI/ADB GMS joint publication.

ADB TA 6440-REG: Facilitating Regional Power Trading and Environmentally Sustainable Development of Electricity Infrastructure in the Greater Mekong Subregion, included analysis of SEAs and EIAs in the GMS countries and identification of gaps, needs, and areas for strengthening systems. On completion of TA 6440, the review of the regulatory framework for developing regional power trading and implementation of the SEA still needed follow-up work. Implementation of the SEA was therefore continued through another regional TA (TA 7764-REG), which provided valuable lessons on how the SEA process can be used for power planning.[72] ADB asserted that: "The study is the first in the world to incorporate SEA, which focuses on sustainability and policy making, into power development plans (PDPs). Specifically, the study incorporates SEA into the PDPs in the Greater Mekong Subregion (GMS) to arrive at an optimal power development trajectory for the GMS as a whole."[73] The TA produced three knowledge products relating to SEAs:

(i) Integrating SEAs into power planning.

(ii) Identifying sustainability indicators of SEAs for power planning.

(iii) How SEAs can influence PDPs—comparing alternative scenarios for power planning.

Outside the GMS, experience with SEAs for PDPs and power master plans is noticeably sparse. However, globally there have been several hydropower SEAs, including ones undertaken in a PDP context. For example:

(i) Koshi Basin Nepal, an area of high ecological value;

(ii) small hydropower strategy in Georgia;

(iii) several applications in South Africa;

(iv) the National Impact Assessment Program in Pakistan;

(v) hydropower impacts in Albania;

(vi) the MRC Mainstream Dam SEA for the GMS; and

(vii) the International Finance Corporation (IFC) SEA of the Hydropower Sector, published in Myanmar.

Some of these SEAs are directly linked to planning decisions such as a PDP and some are not.

72 ADB. 2010. *Technical Assistance for Ensuring Sustainability of GMS Regional Power Development*. Manila.

73 ADB. 2015. *How Strategic Environmental Assessment Can Influence Power Development Plans: Comparing Alternative Energy Scenarios for Power Planning in the Greater Mekong Subregion*. Manila.

SEAs in the GMS

The status of SEAs in the GMS varies markedly:

(i) The PRC and Viet Nam have formally adopted SEA in their legal structure and have legal, administrative, and procedural frameworks and technical guidelines for SEA implementation.

(ii) In the Lao PDR, the 2012 Environmental Protection Law defines SEAs and states that an SEA shall be conducted while developing policies, strategic plans, and programs (for the energy sector, etc.).
   (a) As Article 19 of the Environmental Protection Law defined the SEA application as an important task, the Minister of Natural Resources and Environment issued a Decision on Strategic Environmental Assessment (SEA) No. 0483/Ministry of Natural Resources and Environment (MONRE) of 6 February 2017 stipulating that SEAs were a required part of strategic and sector development plans.

Table 6: Greater Mekong Subregion Experience with Strategic Environmental Assessments—Selected Examples

Example	Features
North–South Economic Corridor–the Lao PDR, Myanmar, the PRC, Thailand	SEA provides a top-level umbrella planning framework for this transport corridor.
SEA of Golden Quadrangle Tourism for the Lao PDR, the PRC, Thailand	SEA to provide a better understanding of how development pressures impact on cultural and natural assets that are the area's main tourism attractions.
Great Western Development Strategy for the PRC	Aims to examine environmental impacts and risks and investigate possible modifications to specific elements of the strategy.
Mekong River Commission Basin Development Plan	SEA used to refine the Basin Development Strategy and protect the environment, e.g., flow to and from Tonle Sap lake.
Sida Country Strategy for Viet Nam	Environment and sustainability issues better integrated with other development issues.
National Tourism SEA for Cambodia	SEA aims to ensure that environmental quality is maintained in all tourism destinations, in the face of rapid growth in tourist numbers.
Nam Theun 2 Hydro Project—the Lao PDR	This pilot SEA had a broader focus than a traditional ESIA and considered sector-wide issues and transboundary impacts.
Golden Quadrangle Tourism SEA—the Lao PDR	This SEA was prepared under the Asian Development Bank (ADB) Core Environment Program.
SEA on agriculture and tourism in the Oudomxay province–the Lao PDR	This formed part of the ADB Nam Ngum River Basin Development Project.
PDP for Viet Nam	SEA has been applied to the PDP planning process in Viet Nam since 2006.

Lao PDR = Lao People's Democratic Republic, PDP = power development plan, PRC = People's Republic of China, SEA = strategic environmental assessment, ESIA = environmental and social impact assessment.
Source: Ricardo Energy & Environment.

(b) Departmental SEA Guidelines (No. 3063/MONRE. Department for Environmental Quality Promotion) were subsequently approved on 31 December 2018 and will form the basis for the future development of the SEA system. The guidelines define the scope and content of an SEA, including key steps in the SEA process.

(iii) Thailand has draft SEA regulations and guidelines and is legalizing the process as of July 2020.

(iv) Cambodia and Myanmar have not yet committed to SEA, but both have taken initial steps to accrue SEA experience.

Specific SEAs in the GMS are discussed further in Appendix 2.

The SEA for the Revised PDP VII was more fully integrated into the PDP preparation, including the definition of the PDP scenarios to include increased use of renewable energy and energy efficiency and be in line with new policies on renewable energy, climate change, and environmental protection. The Revised PDP VII reduced the expansion of coal-fired generation (about 16 coal-fired plants from 2027 to 2030) through lower demand and increased energy efficiency and renewable energy, resulting in reduced air pollution to a value of about $4 billion/year.

4.2 International Best Practice of Strategic Environmental Assessments in the Power Sector

General

This subsection aims to identify the key elements of a power sector SEA based on international best practices. Subsection 3 questions whether SEAs have evolved sufficiently in the power sector for best practice to be clearly defined. ADB TA 7764-REG—published in 2010—indicated that it was the first in the world to incorporate SEAs into PDPs (footnote 72).[74] Before then, PDPs in the power sector had only been applied to subsectors such as hydropower, tidal power, or renewable energy. In 2012, the World Bank published a review of SEA projects it had been involved with.[75] This review stated that: "Nearly all of the SEAs in the energy sector have been for hydropower projects." Apart from a multisector SEA in Egypt in 2003, the

---

74 Footnote 72 and subsection on SEA and the power sector.

75 World Bank. 2012. *Strategic environmental assessment in the World Bank: learning from recent experience and challenges*. p. 54.

power SEAs mentioned in the review were those for the hydropower subsectors in the Lao PDR, Nepal, and Viet Nam.

Since the 2012 World Bank review, SEAs in the power sector—apart from that for Viet Nam's Revised PDP VII approved in 2016—continue to be largely restricted to regions or subsectors such as hydropower, rather than national PDPs.

Determining SEA best practice in the power sector is a challenging enterprise. Application of SEAs to national PDPs outside Viet Nam is largely either non-existent or not in the public domain. A notable exception, however, is in the PRC, where their preliminary EIAs are broadly similar to SEAs. There are, nevertheless, several documented examples of SEAs being applied to power subsectors, such as hydropower, renewable energy, etc. Consequently, several such SEAs prepared over recent years are compared to establish whether a consensus is developing on best-practice approaches. These include:

(i) the MRC SEA for Mekong Mainstream Hydropower;

(ii) Myanmar, SEA of Hydropower;

(iii) The PRC, Preliminary EIA Methodologies;

(iv) Viet Nam, Hydropower SEA following PDP VI;

(v) Viet Nam, SEA for PDP VII; and

(vi) Viet Nam, SEA for Revised PDP VII.

SEA Approaches

An SEA is a process of evidence-based analysis of social and environmental issues within the context of strategic planning. There are several basic concepts in an SEA:

(i) It should have balanced analysis to build consensus, including recognizing trade-offs and linking sector goals to national development.

(ii) All interested and affected stakeholders must participate in key stages of the SEA.

(iii) The professionals executing the SEA must be seen to be unbiased and objective, with no preconceptions over what are desirable outcomes.

(iv) It has legal status. It is now a legal requirement in many countries—including across the GMS—to undertake an SEA for particular types of plans.

(v) It must be fully integrated into—not separate from—the strategic planning process.

There are several broad aims and objectives of SEAs—for any sector and not solely for power:

(i) An SEA helps achieve environmental protection and sustainable development by
   (a) consideration of social and environmental effects of proposed strategic actions,
   (b) identification of the best practicable environmental option, and
   (c) early warning of cumulative effects and large-scale changes.

(ii) An SEA strengthens and streamlines project EIA by
   (a) prior identification of the scope of potential impacts and information needs,
   (b) clearance of strategic issues and concerns related to the justification of proposals, and
   (c) reducing the time and effort necessary to conduct individual reviews.

(iii) An SEA integrates the environment into sector-specific decision making by
   (a) promoting environmentally sound and sustainable proposals, and
   (b) changing the way decisions are made.

An understanding of the basic characteristics of an SEA is useful to this review of best practice since these should apply to power SEAs—irrespective of whether these are for a national PDP, hydropower expansion plans, geothermal energy plans, etc.

To a much greater extent than for EIAs, SEAs are decision-oriented; in addition to identifying social and environmental problems, SEAs also seek to identify and agree on solutions to these problems. Best practice in governance requires that solutions be determined after a thorough consultation process with stakeholders. A successful SEA is therefore a balance between technical analysis and structured stakeholder consultations.[76]

A good practice SEA includes an assessment of potential social and environmental impacts, together with their risks and uncertainties. It then determines the internal (e.g., mitigation requirements) and external (e.g., health impacts of air and water pollution) costs associated with each of these impacts. Assigning costs to social and environmental impacts in the plan requires rigor in data and evidence gathering, and recognized methodologies—where possible—for the economic valuations.

[76] TA 9003 has observed that stakeholder consultations are open to a range of interpretations. In countries such as the US and the UK, the processes for public consultation are supported in the legislation and failure of line agencies to observe these processes can—and are regularly—brought before the courts. In many other countries, however, including many of the GMS countries, stakeholder is routinely interpreted as just the agencies with an interest in the sector. Consultation with NGOs and the public, for example by inviting comment and evidence on draft proposals published in the public domain, has yet to become the norm.

SEAs are not undertaken based on a single, best-estimate plan; diverse alternatives are considered. SEAs contain scenarios that consider feasible alternative development options for achieving the desired planning outcomes.

Including an SEA in the preparation of a power sector plan or program is not undertaken solely for environmental protection purposes; if done correctly it can improve the whole planning process. For example, an SEA can build a constituency of support for the plan by having wider stakeholder involvement. An analysis of impacts can also provide a fuller picture of the implications of different power options. Assigning economic values to these impacts—i.e., internalizing the externalities—facilitates a quantitative assessment of options to provide the mix that is optimal for the country's future development.

An SEA is a means for ensuring wider national development priorities such as green growth and climate change mitigation are integrated into the plan's preparation.

An SEA can speed up the whole development process by identifying individual investments that are likely to have serious social and environmental impacts—which can cause delays and controversy. By doing this early in the planning process, such projects can be eliminated from future consideration. It is also a means to understand the cumulative impacts of a number of developments, such as a series of dams on a river or several thermal power stations around a city, that are not picked up by project EIAs.

SEAs have different methodologies, some with several process stages. Despite this, all SEAs have certain common characteristics (Figure 5). For strategic plans, SEAs should predict the potential impacts (positive and negative) of different planning options and evaluate whether these impacts are significant enough to require actions to mitigate them, reducing the negative ones and enhancing positive ones.

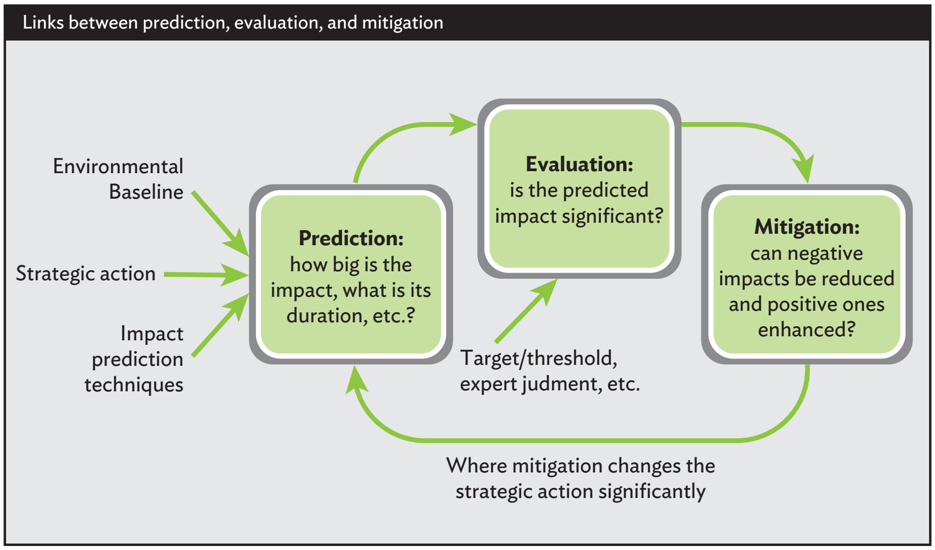
The sequencing in the phases of an SEA is summarized in Figure 6.

Best Practices

The keys to a good SEA are that it is balanced, objective, and evidence-based. Balance requires a set of objectives that are consistent with national development priorities, validated through stakeholder consultation, and tested through thorough analysis that includes judiciously selected scenarios. Objectivity requires consistency throughout the SEA with the established aims and objectives of the SEA. The SEA phases should be consistent with those outlined earlier in chapter 4. Evidence-based requires thorough data collection, sound methodologies, and meticulous analysis.

This subsection on best practices in an SEA must recognize that—apart from recent experience in Viet Nam—applying an SEA to entire national power development plans is extremely uncommon. Unfortunately, while the efforts by the Institute of Energy in Viet Nam to integrate SEA with the preparation of their PDPs present an excellent example to other countries—not least the other countries in the GMS—those SEAs would have been improved appreciably by the allocation of greater resources.

Figure 5: Basics of Prediction, Evaluation, and Mitigation



Source: Ricardo Energy & Environment.

Figure 6: Phases of a Strategic Environmental Assessment

Source: Ricardo Energy & Environment.

On the specific issue of resources, Appendix 2 subsection A2.6 on the SEA for Mekong Mainstream Hydropower notes that it involved 10 international specialists and 13 specialists from four GMS countries, over an elapsed time of 16 months. The SEAs for Viet Nam's PDP VII, comprised a much smaller working group and an appreciably smaller timescale. None of the Viet Nam SEAs in power had enough resources with which to facilitate the gathering of new information or to undertake more exhaustive stakeholder consultations. While the scope of the Viet Nam PDP SEAs and the Mekong Hydropower SEA are not directly equivalent, the Viet Nam SEAs require similar consideration of the various environmentally and socially detrimental impacts of hydropower—while also considering those associated with polluting emissions from the various thermal generation technologies, in proximity to densely populated urban centers.

While it is difficult to provide specific figures for the required resources to undertake a good practice SEA, these should be sufficient to study each technical area at a good level of detail. Access to competent specialists in each of these key areas is required, and they should each have time and budget allocated for information gathering and analysis that is commensurate with the importance of their field to the overall SEA. Stakeholder consultations during each critical phase of the SEA should be undertaken, and—building on the experience of the MRC SEA for Mekong Mainstream Hydropower—opportunities should be sought to interact with stakeholders in fora where they are not obliged to defend their sector mandates.

An SEA is a means for ensuring that wider national development priorities—such as green growth and climate change mitigation—are integrated into the PDP or IRP preparation. Good practice is therefore to ensure that the aims and objectives of the SEA are consistent with those other priorities.

The aims and objectives of the SEA need to be closely defined at an early stage, and best practice suggests that there should be broad stakeholder consultation to validate these. Similarly, since—in addition to identifying social and environmental problems—a key aim of an SEA is to find solutions to those problems, best practice requires that solutions be determined after a thorough consultation process with stakeholders.

A good practice SEA includes an assessment of potential social and environmental impacts, together with their risks and uncertainties. To the greatest practicable extent, they should:

(i) Identify impacts and quantify to the greatest practicable extent: persons affected by pollution, reduction in fisheries production, reductions in agricultural production, hectares of forestry lost, etc.

(ii) Assess risks and uncertainties since impacts can be difficult to quantify accurately from the data available. Alternative scenarios may need to be considered to assess these risks, e.g., the cascade sequencing of dams in a river basin.[77] Scenarios should consider cumulative impacts, e.g., multiple hydropower projects in a basin, or multiple thermal generation projects in an urban conurbation.

[77] Interactive stakeholder consultations may help to identify scenarios or circumstances that are not immediately apparent to the planners.

(iii) Monetize the costs—and benefits—of the impacts using accepted methodologies and, where divergent methodologies are in current usage, ensure that the methods applied accord with stakeholder consensus.

These assessments require a significant investment of time and financial resources, and best practice suggests that an initial investment in this respect is rewarded by an SEA that is more defensible against detractors, and the likelihood that subsequent SEAs will require appreciably fewer resources since data sources and methodologies have—to a great extent—already been defined. In addition to having hard numbers with which to establish SEA recommendations, these numbers can also be included in the economic analyses in the IRP, e.g., by including the external costs in the IRP optimization modeling.

Stakeholder involvement is extremely important to the success of the plan that the SEA supports. Good practice consultation will be carefully designed and implemented, with the likelihood that it builds support for the plan.

A good practice SEA should predict the potential impacts (positive and negative) of different planning options and evaluate whether these impacts are significant enough to need actions to mitigate them—reducing the negative ones and enhancing positive ones. An SEA in an IRP context will recognize that objectives are wide-ranging and sometimes potentially conflicting, e.g., supporting economic growth while reducing GHG emissions. Planners need to postulate scenarios that will examine these objectives and help management—with input from stakeholders—to make well-founded decisions on the way forward.

5 Economic Analysis in Integrated Resource Planning

5.1 Fundamental Issues

General

Before venturing into international best practice and current practices in the GMS countries, it is useful to consider the fundamental aspects of economic analysis in IRP preparation where there may be scope for different interpretations by practitioners. Chapters 2, 3, and 4 have touched upon the subject of economic analysis, particularly in respect of whether GMS countries address the issue of internalizing externalities in their PDPs and, if so, how? Chapter 5 addresses the broader consideration of economic analysis and critical issues such as dealing with externalities, approaches to the costing for GHG emissions, screening supply-side and demand-side options, etc.

Objectives of Economic Analysis

Economic Analysis of Projects

In certain respects, the economic analysis of an individual project has some differences of approach to that for a complete sector expansion plan such as a PDP or IRP. A widespread prerequisite for national governments or IFIs such as ADB,[78] World Bank, or European Investment Bank is that to qualify for support, the individual project should represent the most efficient or least-cost option of all the feasible alternatives for achieving the required project benefits and when the benefits can be valued, the project will generate a positive economic net present value using the country's specified discount rate.[79]

The reference to least-cost option in the previous paragraph is the link to PDPs and IRPs. A PDP is a sequence of infrastructure additions—typically generation and transmission projects—to meet the best estimate of system demand at an optimal level of supply reliability, at least cost. The definition of least cost is a key point of departure. Legacy least-cost expansion programs were typically undertaken in economic terms, but with a narrow interpretation of economic. Modern, best practice IRPs have similarities with the early forerunners but contain a much broader scope and greater emphasis on social and

78 For more information, refer to footnote 58.

79 The ADB Guidelines specify using the minimum required economic internal rate of return (EIRR) as the discount rate, such that the project has an EIRR higher than the discount rate. Strictly, an economically viable project must meet two conditions: (i) the present value of the project's net benefits (the NPV) must not be less than zero; and, (ii) the NPV of the project must be higher than or equal to the NPV of the mutually exclusive project alternatives.

environmental sustainability. Drawing from subsection 2.2, an ideal or good practice IRP has characteristics that differentiate it from earlier approaches:

(i) Stated aims should integrate with national policies, laws, regulations, and guidelines on sustainable growth, social equity, transparency, and good governance, international commitments to limit GHG emissions, etc.

(ii) Stakeholder consultation should be held at key stages in the IRP preparation process and with an inclusive interpretation of consultation that includes participation by members of the public.

(iii) A broad range of technologies and generation unit sizes should be considered as candidates, and not simply exceptionally large projects using the technologies that the utility is most familiar with.

(iv) A wide range of renewable energy technologies should be considered as candidates—both large and small—including programs for large numbers of very small installations such as rooftop solar photovoltaics.

(v) A wide range of energy efficiency and DSM initiatives should be considered as candidates.

(vi) A good range of candidate IRPs should be developed that attune the diverse—and sometimes conflicting—goals that underpin the IRP, and these should be subjected to rigorous analysis, including risk analysis.

(vii) Social and environmental assessments should be undertaken for all supply options, including imports, and demand options.

(viii) Continuous monitoring of the implementation of the IRP should be undertaken, for two good reasons:
    (a) to bring to the attention of the authorities any information suggesting that a switch away from the Preferred IRP to a Contingent IRP ought to be considered; and
    (b) to monitor outturns to improve the data collection methodologies, parameter selection, and analytical methodologies for future IRPs.

Many PDPs undertaken by utilities in the US are badged as IRPs but—while often of a high standard in terms of consultation and consideration given to a wide range of renewable energy and energy efficiency options—often fall well short of an ideal IRP by considering only financial costs to the utility and not considering the cost of important externalities.

Discounted cash flow techniques—using costs and benefits in economic terms—are applied to expansion programs like in individual projects. In an IRP, however—especially an IRP with SEA—the preferred IRP selected at the end of the preparation process may not necessarily be the least-cost candidate IRP considered.

Due to the diversity of goals and need to strike balances, complementary analytical methods are also applied; multicriteria analysis (MCA), for example.[80]

The projects in an IRP will be the least-cost option at the time they are scheduled to be commissioned according to the IRP's schedule. A caveat to this statement is that they are the least-cost option based on the information and assumptions made during the preparation of the IRP. Since IRPs typically have a planning horizon of 10–20 years, there is ample scope for departures from the original assumptions. For example, actual demand may be appreciably higher or lower than forecast; fuel prices are notoriously volatile and may change significantly; the comparative costs of technologies can change—the cost of wind and solar technologies have demonstrated this over the past several years; and the social and environmental external costs of projects may become more prominent and costlier—such as a rise in the cost of GHG emissions, etc. The combination of such factors translates to IRPs that become outdated quite quickly, and hence constantly in need of frequent updates.

Developing the stream of economic costs and benefits is at the heart of economic analysis. For a project, this requires consideration of two scenarios: with and without the project. Monetized values of costs and benefits are determined for the years in which they arise, neglecting those that are common to both with and without scenarios. External effects that affect the national economy, but which are not captured in market transactions, should be included. A caveat to this statement is that many of these externalities are difficult to monetize and—for some—the scale of the monetized values does not warrant the time and effort required to estimate them. The challenge for planners is to foster an understanding of which externalities have the potential to influence the outcome of the analysis and to focus efforts on determining robustly defensible values for these. The ADB guidelines suggest that: "Where it is important, but difficult to establish monetary values for such (external) effects, they should be identified and a qualitative discussion be provided."

Economic analysis is usually conducted using real prices. Real prices do not include inflation during the life of the project, whereas nominal prices reflect any inflation or deflation occurring. Real prices should not be confused with constant prices, since real prices do not necessarily remain constant and may change in response to underlying factors such as supply and demand in the market.

Economic analysis requires that the project costs and benefits should be expressed in economic—as opposed to financial—values. The conversion of financial values into economic values is a concept known as "shadow pricing" and is required to be applied to project outputs and inputs. The methodologies for determining shadow prices are quite complex and beyond the scope of this document.[81] However, with the effects

---

[80] European Investment Bank. 2013. *The Economic Appraisal of Investment Projects at the EIB.* Brussels http://www.eib.org/attachments/thematic/economic_appraisal_of_investment_projects_en.pdf.
Multicriteria analysis (MCA) is a tool used to assess the different investment alternatives available to achieve a given set of outcomes.

[81] The intricacies of shadow pricing include require various levels of categorization: between project outputs and inputs, between internationally traded and non-traded goods and services, and between incremental and non-incremental outputs and inputs.

of globalization having reached most countries around the world, the differential between financial and economic prices is now considerably narrower than it was a few decades ago.

While IRP and IRP with SEA has generally added focus on the internal and external costs associated with adverse social and environmental impacts, this subsection would not be complete without mentioning the key aspects of valuing costs and benefits for power projects. The transactional costs associated with increasing the system capacity should include not only the cost of the generating plant but also the incremental cost of the additional transmission and distribution infrastructure needed to transmit the incremental power to end users.[82]

To understand the benefit stream from an individual power project it is necessary to understand that the benefit to end users is only realized through its additional contribution to the overall power system. The contribution of a power generation project, for example, may be realized through one or more mechanisms:

(i) by incrementally expanding the capacity or improving the overall efficiency of the system by displacing or by rehabilitating older, less-efficient facilities;

(ii) by non-incrementally improving the fuel efficiency and/or variable O&M costs arising from the displacement or rehabilitation, with output remaining unchanged; and

(iii) in the case of renewable energy projects displacing fossil fuel plants, non-incremental benefits accrue in the form of cost savings, plus the external benefits associated with reduced GHG emissions and other net environmental benefits.

Incremental and non-incremental benefits are valued differently. The increased output has two components. The first of these is supply to new users, where the energy supplied displaces alternatives to grid electricity such as kerosene lamps, small portable generators, batteries, etc. The benefits from this are classified as non-incremental and are valued using the cost savings since main electricity is almost invariably significantly cheaper than the commonly available alternatives. The second component is the increased consumption by new and existing customers. New customers, with the cost advantage of main electricity, typically increase their monthly energy consumption once they are connected. Existing customers tend to increase their energy consumption as the economy expands and as their incomes rise. This incremental consumption by new and existing customers is valued using the principle of willingness to pay.

The measurement of willingness to pay for electricity is dependent on a reliable estimate of the demand for electricity function. This is potentially complicated since no two customers' behavior is the same. The academic literature suggests various

82 Incremental and non-incremental attributes relate to the difference between the with and without project scenarios.

complex approaches.[83] However, practitioners typically adopt simplified approaches for each of the main customer categories: residential, small commercial, large commercial, industrial, etc.

When the power project includes system reliability improvements, there is an economic benefit associated with this improvement. Customers' willingness to pay for an improved service should be estimated and included in the analysis as an avoided cost. The energy not served and hence the total cost of energy unserved (CUE) will be reduced as service reliability improves. The CUE can be estimated for each customer category by a combination of methodologies such as the cost of alternatives (e.g., backup generation), the value of lost production, the value of lost income or leisure time, etc.

Economic Analysis within an IRP

Risk Analysis

There is uncertainty in most of the values estimated for parameters used in an IRP. For parameters such as fuel prices, capital costs, electricity demand, there is ample evidence of this uncertainty and the repercussions of not having sufficiently robust processes to withstand these uncertainties. Modeling for risk and uncertainty is therefore an important element of economic analysis, including IRPs. A common danger is to limit the analysis to the common uncertainty types such as those mentioned above. Planners need to be more unconstrained in their consideration of uncertainties. For example, how many planners anticipated the impact of technologies such as solar photovoltaics, wind energy, batteries—especially when coupled with deregulated markets, venture capital, and innovative web-based entrepreneurs? With very good reason, these technologies have been labeled as disruptive—as many businesses rooted in conventional thermal technologies have found to their cost. Unanticipated disruption can arise from technologies, markets, politics, environmental regulations, etc. Planners can help themselves to anticipate disruption, to some extent, by listening to, and engaging with, knowledgeable stakeholders during the consultation process, i.e., a consultation process that is truly open-ended and with genuine two-way information flows (Borison 2016).[84]

Borison advocates that a stochastic model is developed for each key source of risk identified by planners. Deterministic optimization models such as Aurora, Strategist, and System Optimizer are not recommended to identify candidate resource plans, however. Instead, a wide range of approaches ought to be used to identify the candidate portfolios, and a decision analysis or real options approach adopted to evaluate them. However, system production simulation models are still required to evaluate the impacts of the portfolios under the various outcome scenarios (footnote 84).

---

[83] ADB. 2002. *Measuring Willingness to Pay for Electricity.* Manila.

[84] A. Borison. 2016. Berkeley Research Group. *Uncertainty in IRP: Common Pitfalls and Best Practices.* USA.

Microsoft Excel add-ins such as @Risk and Crystal Ball are relatively inexpensive tools to undertake the risk analysis and require judicious selection of probabilities and distributions.

Valuation of Externalities

Chapter 2 remarked that one of the key differences between legacy least-cost approaches to PDPs and good practice IRPs is that the least-cost approach does not—generally—capture the costs and benefits of externalities. It was also mentioned that in some jurisdictions it is not uncommon for little or no consideration of externalities to be made—especially by utilities in the US. D'Sa—a relatively recent and authoritative source—mentioned more on this subject:[85]

> Integrated resource planning (IRP) is a planning method in which the requirement of a resource is met through combinations of supply increases and conservation of demand, while minimising the costs to the firm and to society. Countries around the world have programmes devoted to promoting renewable sources of electricity and/or improving the efficiency with which it is used. But there are relatively few cases where the comparison of both supply- and demand-side options, and their externalities, is an integral part of the evaluation process.

An explanation of externalities and their relevance to IRPs is useful at this juncture. The economic concept of an externality has existed for over 100 years. It has been defined as the cost or benefit that affects a party who did not choose to incur that cost or benefit. Economists typically advise national governments to adopt policies that will internalize an externality, so that costs and benefits will affect mainly parties who choose to incur them. The power sector can provide a great many examples of where external costs are borne by communities that receive little or no benefit from a particular facility. In remote and often mountainous regions, it is not uncommon to find communities blighted by waterborne disease or plunged into deeper poverty due to the construction of a large hydropower dam in their neighborhood—without even having the opportunity to receive a modest supply of electricity from the project.

Similarly, a coal-fired power station sited near to a community can condemn some members of that community to chronic lung conditions and/or premature death due to airborne pollution from stack emissions of SOx, NOx, and particulate matter—or even from wind-borne fly ash. By adequately determining the true economic cost of such externalities in these examples and internalizing the costs—and any benefits—into the economic analysis, the likelihood is that alternative siting or alternative technologies could be applied, the social and environmental impacts mitigated in some way, or even commensurate compensation paid to project-affected persons.[86]

A negative externality is anything that causes an indirect cost to individuals. The health impacts and any long-term loss of livelihoods mentioned in the previous paragraph are all examples of negative externalities.

---

[85] A D'Sa. 2011. The International Energy Initiative (IEI) is a nongovernment organization with the objective to initiate, strengthen, and advance the efficient production and use of energy for sustainable development.

[86] Large reservoirs for hydropower projects can also yield external benefits, such as reduced flooding.

Mitigation measures, such as flue gas desulfurization or compensation payments, are not externalities since they are direct monetary payments. Conversely, a positive externality is any difference between the private benefit of an action or decision to an economic agent and the social benefit.

Viet Nam's Experience with Externalities

International NGOs, such as the Stockholm Institute, and independent consultants, supported the Viet Nam Institute of Energy over several years with the SEAs for PDP VI, PDP VII, and the Revised PDP VII. The Institute of Energy has been very proactive in adopting SEA, which has resulted in a much more comprehensive integration of social and environmental externalities into the overall PDP methodology.

The three SEAs have facilitated a sound understanding of the key social and environmental issues arising in the power sector, and thus focusing efforts to internalize the principle externalities into the PDP analysis. The key issues identified in Viet Nam—most of which apply equally to other GMS countries—include:

(i) loss of forest and biodiversity due to the construction of power plants and transmission lines;

(ii) downstream hydrological changes, issues related to sustainable water resource management, and concerns about the potential downstream salt intrusion, all caused by the construction of dams;

(iii) impacts on the environmental quality of water through the use of cooling water by thermal plants and the damming of rivers for the construction of hydropower plants;

(iv) solid waste and toxic waste from thermal power projects, especially coal-fired thermal plants, and oil leaks from transformers;

(v) natural resources efficiency and conservation issues related to
  (a) development of power plants, which use fossil fuels such as coal, oil, and natural gas, which themselves are finite natural resources at risk of exhaustion, and
  (b) contamination of soil, water, and rock when used in power development projects, especially during construction;

(vi) environmental risks and accidents, which are natural or induced by humans. Some of these risks and impacts are related to fire, explosion, radioactive leaks, and toxic pollution;

(vii) climate change caused by emissions of CO_2 and other GHGs from thermal power plant fuels (especially coal) and water reservoirs of hydropower plants;

(viii) energy security issues in the context of
  (c) declining reserves of traditional primary fuels, resulting in increased reliance on imports of such fuels at rising prices, and
  (d) potential for environmental conflicts, risks, and accidents related to sharing scarce water resources, land, forests, and other natural resources for project development, etc.;

(ix) social issues, resettlement, and impoverishment related to the displacement of people due to the construction of power plants, dams, or reservoirs;

(x) livelihood issues related to the standard of living affected by resettlement caused by power plant development;

(xi) community health issues caused by the detrimental environmental impacts of power projects on water, soil, and air; and

(xii) agriculture and food security issues; agriculture issues are related to the loss of agricultural land due to industrial and power plant development in the context of increasing population and deteriorating land quality. Food security is affected by climate change.

Some of these issues are detrimental to the global community, whilst others are felt more acutely by communities local to projects. To varying degrees, they are costs associated with individual projects that should be offset against the benefits—principally in the form of additional electricity supplies—when system expansion studies are undertaken. Unfortunately, quantifying and monetizing many of these impacts is a challenging exercise. Transactional costs, such as compensation payments to households and communities relocated to make way for a power plant, hydropower reservoir, or transmission line, are straightforward to monetize for inclusion in the analysis. Less simple, however, is quantifying and monetizing the social cost of lost livelihoods, or degraded health and welfare due to pollution.

The loss of forest and biodiversity, due to a new transmission line, for example, provides a useful exercise. The impacts are of two types: (i) the resource value of natural resources, valuing where possible both the inherent value of the resource—for timber or for fruit crops—and the cost of mitigation measures to ameliorate any negative impacts; and (ii) the inherent biodiversity value of the ecosystems that are at risk of being affected by hydropower development.

The biodiversity assets cannot be given either quantitative (e.g., number of species affected) or economic values as relevant data do not exist in Viet Nam, and the biodiversity issue is dealt with by a qualitative and quasi-quantitative screening process within the SEA. This approach is also adopted for hydropower projects that create large reservoirs, with the SEA process screening out sites that would create an irreversible loss of biodiversity.

The challenges with quantifying and monetizing an externality such as the loss of forest and biodiversity remain for those projects not screened out by the SEA.

The impacts are internalized by budgeting for community-based forest management schemes as a mitigation measure. This approach, as part of a resettlement action plan, has become a standard feature over the past couple of decades, but success requires adequate funding and oversight. Funding is often through a levy on the energy produced by the project $0.08/kWh (in 2017).

The degradation of landscapes and consequential impacts on tourism is not quantified in Viet Nam as of 2020. This is a challenging area for economists since tourism itself often has detrimental environmental and social impacts.

Thermal power plants in coastal areas or alongside rivers can raise the water temperature significantly—often around 7°C–8°C—which adversely impacts on river and marine ecology. The scale of the temperature rises and environmental impacts are difficult to quantify until project EIAs are undertaken. Nuclear power plants would have similar impacts. The SEA can provide screening to safeguard against incremental adverse impacts.

Issues such as changes to hydrological regimes or saltwater intrusion are handled through the SEA, rather than by monetizing the impacts, and typically recommend a series of water management measures.

Incremental impacts of multiple hydropower projects in a river basin are resolved in the SEA—as they are in the Myanmar Hydropower SEA (Appendix 2 Subsection A2.4)—by applying screening based on these river basins.

Viet Nam's PDP VII estimated the physical quantities and the impact severity of the four main pollutants (CO_2, SO_2, NOx, and particulate matter) for each existing and planned thermal power station. The impacts of acidification due to SO_2 emissions are already being encountered in various parts of Viet Nam, due mainly to stack emissions from coal-fired power stations. Most noticeable are the impacts on freshwater aquatic ecosystems. All three main impacts of air pollution from thermal power plants— climate change, acidification, and human health—are significant. The calculation of cost associated with these impacts has been based on international norms with adjustments to the Vietnamese context. The Institute of Energy adopts a CO_2 price based on international market values.

Management of coal ash produced from the coal combustion process poses an increasingly serious problem in Viet Nam: storing ash usually requires agricultural land to be taken out of production, with consequential loss of livelihoods; pollutants leach into soil, watercourses and, aquifers; and wind-blown ash has adverse impacts on human health. The Institute of Energy notes that there are no available data as of 2020 on the economic cost of ash disposal and the subject requires further attention before the adverse impacts can be quantified and monetized.

The SEA has developed a system of indicators to measure environmental and social impacts associated with power generation developments (thermal, hydropower and other renewables, and nuclear) and related transmission lines. The indicators have been designed to measure the specific impacts related to the types of power generation:

(i) **Thermal power generation**. Impacts related to climate change (through GHG emissions); acidification (through stack emissions from thermal power plants); impact on health from air pollutants from the thermal plant, and loss of habitat, displacement of people; and impacts from cooling waters and disposal of solid waste from thermal power plants.

(ii) **Hydropower generation**. Impacts causing resettlement, loss of forests, changes in hydrology, and loss of vulnerable ecosystems and biodiversity.

(iii) **Nuclear power generation**. Risk of nuclear leaks, cooling water impacts, and radioactive waste disposal.

(iv) **Other forms of renewable generation**. Impacts on land used, impacts on residential areas and ecosystems.

(v) **Transmission lines**. Impacts on forests, ecosystems, including health impacts from electromagnetic fields.

Internalization of the externalities is undertaken for only a minority of these impacts, and these are summarized in Table 7.

The use of life cycle assessment tools and models can also be considered in quantifying some of these impacts, including climate change. Life cycle assessment would also be appropriate for assessing other categories of more specific environmental factors, such as acidification, eutrophication, emissions of particulate matter, tropospheric ozone, human toxicity, ecosystem toxicity, etc.

Table 7: **Methods for Valuing Externalities**

Generation Type	Impact Type	Valuation Approach
Thermal Power	Climate Change	CO_2 price from the international market at the time preparing the PDP/SEA.
Thermal Power	Health Impacts	Estimate the damage cost for health care based on the studied results of Mans Nilson (SEI) in 2009 of the major environmental program in the GMS.
Thermal Power	Habitat Loss	Estimate the economic value of forest ecosystem services and biomass based on price rate which is issued by the Ministry of Agriculture and Rural Development (MARD).
Hydropower	Forest and Habitat Loss	Estimate the economic value of forest ecosystem services and biomass based on price rate which is issued by MARD.
Transmission Lines	Forest Loss	Estimate the economic value of forest ecosystem services and biomass based on price rate which is issued by MARD.

CO_2 = carbon dioxide, GMS = Greater Mekong Subregion, PDP = power development plan, SEA = strategic environmental assessment.
Source: Ricardo Energy & Environment.

Approaches to the Costing of GHG Emissions

CO_2 and other GHGs need to be quantified in terms of their metric tons of coal equivalent (tCO_2e), which will vary with the fuel characteristics and the efficiency at which the plant operates. Applying a cost to the CO_2 emissions requires a decision on the most suitable costing methodology; some authorities use values based on carbon trading markets, while others use values based on estimates of the social cost of carbon. The social cost of carbon valuation is typically considerably greater than valuations based on carbon trading markets. Other methodologies are also available.

The CO_2 valuation practiced in Viet Nam is to adopt international market values. For the Viet Nam PDPs, the Institute of Energy is understood to have used CO_2 market values of around $7 per metric ton (t) (in 2017 US dollars). For the Balmorel modeling undertaken for Viet Nam by the Danish Energy Agency, scenarios were assessed wherein the social cost of carbon values of $45/t was adopted. It has been estimated that the CO_2 value required to limit global warming to 1.5°C, relative to pre-industrial temperatures, is in the range of $40/t–$80/t.[87] Refining these estimates is challenging because there is no global consensus on a single figure for the social costs of carbon.

Economic Analysis and Demand-Side Issues

In some jurisdictions—including several states in the US—demand-side measures such as energy efficiency and DSM are stipulated in the policies and regulations of those jurisdictions, and the goal of the utility is to comply with these. Elsewhere—and to comply with the strict definition of an IRP—supply-side options are treated with equivalence to supply-side options, and are deployed to meet forecast demand to the extent that it has less economic cost than deploying supply-side options. The key question for planners is not whether a measure saves a monetary value of energy greater than the cost of implementing the measure, it is whether the measure is less costly—in economic terms—than other supply- or demand-side options for meeting customer demand, subject to risk and uncertainty considerations.

A statistic from the 2010 IRP prepared by the Northwest Power and Conservation Council in the US, is that 85% of its projected demand growth over the 20-year planning horizon could be met through energy efficiency.[88] To arrive at this conclusion, the council evaluated the costs and risks of thousands of possible resource portfolios, covering 750 future scenarios. Planners must have access to the best possible information on the costs and other key characteristics of generation, transmission and distribution, and demand-side measures.

---

87 M.H. Clough. 2019. *A bold new plan to tackle climate change ignores economic orthodoxy. The Economist.* 7 February. ADB is understood to apply a value of $37/$tCO_2e$ to the social cost of carbon.

88 The Northwest Power and Conservation Council is a regional planning organization engaged to develop IRPs for the Bonneville Power Administration (BPA) that do not simply place demand-side options on an even footing with supply-side options, but make energy efficiency the highest-priority resource for meeting electricity demand. Consequently, they assign energy efficiency an assumed 10% cost advantage over supply-side options.

For energy efficiency, there is a general need for the GMS countries to develop normative cost figures for the costs and likely effectiveness of energy efficiency programs and national targets in reducing future demand growth.

One approach to the screening of energy efficiency and other demand-side options—and one that does not require additional software—is to create levelized cost curves for these options that are comparable with the similar curves for supply-side options, and allowing the optimization model to select an optimum mix from the supply-side and demand-side candidate options.[89] A key challenge with this approach, however, and perhaps something that supports the case for setting demand-side policy targets, is that accurate information is available on the costs and effectiveness involved with any load-reduction option.

Promoting energy efficiency is not only good for customers, but it also has an important role in helping to ensure that future energy needs are met. Because technologies continue to change, it is important to constantly evaluate the market potentials and programs that have an impact on energy consumption to help ensure they meet changing needs such as evolving technologies, updates to building codes, and product standards.

Market costs in renewable energy did not fall fast during 2000–2012 when feed-in tariffs (FITs) were the dominant policy mechanism to promote and support RES. The FIT mechanism did not reveal the real cost of projects.

An emerging trend for the screening of renewable energy options over the last few years consists of allocating the lowest possible subsidy for an energy or capacity product using a competitive and open bidding procedure. It ensures least-cost (and expeditious) development since it provides a vehicle for tendering projects transparently—as opposed to applying a bilateral or negotiated basis—thus building investor confidence in the system.

It is a similar concept to the consolidated policy reverse auctions for long-term contracts, in which companies compete to receive a subsidy above a given starting price, as opposed to a silent auction where prices are bid up. A buyer offers a contract out for bidding. Multiple sellers are then able to offer bids on the contract. Sellers compete to offer lower bids than their competitors while meeting all the specifications of the contract. The buyer may award the contract to the seller who bids the lowest price. Alternatively, a buyer may award contracts to suppliers who bid higher prices depending on the buyer's specific needs regarding quality, lead time, capacity, or other value-adding capabilities. The interest of bidders to be awarded a subsidy that offers high profitability will be offset by the need to bid as low as possible to ensure being allocated the project. This mechanism uses competition among bidders to reveal the real cost of projects and ensures the

[89] State and Local Energy Efficiency Action Network. 2011. *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* Both PacifiCorp and the Northwest Power and Conservation Council have used levelized cost curves to evaluate demand-side options as part of their recent IRPs.

least-cost development of the system. As the market evolves, possible subsidies will converge to zero. To capture the descending evolution of costs, this type of auction is usually periodic—at least annually—to capture developments in technology and to deter colluding behavior. Iterative tenders allow private actors to bid a plant price based on the actual costs of doing business (i.e., revealing their actual cost). If competition among participants is sufficient, their interest to close the deal will reveal the actual costs.

5.2 International Best Practice

General

The key elements in an IRP where economic analysis is applied include

(i) the screening of the options for consideration as candidates—on the supply-side and the demand-side—in the IRP,

(ii) the internalization of externalities in the IRP,

(iii) the optimization of candidate IRPs, and

(iv) the assessment of candidate IRPs.

Although supply-side and demand-side options have different characteristics, there are particularly good reasons why their screening is best considered in an integrated fashion.

Identifying international best practice in each of these areas is challenging. Not all IRPs are documented in the public domain. Of those that are, the documentation tends to summarize the activities undertaken, rather than discussing any simplifications or omissions. The treatment of externalities, particularly the treatment of GHG emissions, is one such area that is less well explained.

Many of the IRPs in the public domain have been produced by utilities in the US. For reasons advanced elsewhere in this document, regulation of power in the US is largely devolved to individual states, who have ample discretion to develop their own set of goals, targets, priorities, etc. Many of these IRPs are excellent in one or two respects, such as developing a wide range of IRP candidates to address the range of goals; considering demand-side options, especially energy efficiency; considering relatively small-scale renewable energy supply options; and in undertaking transparent and participatory stakeholder consultation. The key shortcoming of these IRPs, however, is that they are not undertaken using economic values, and the internalization of externalities is—at best—extremely limited.

The consideration of best practice in IRP preparation, and specifically the economic analysis within an IRP, needs to carefully examine IRPs undertaken in developing countries like the GMS member countries. In addition to several well-documented

IRPs, there are also reviews of IRP best practice in developing countries that provide a useful resource for this enterprise.[90] A distinguishing feature between industrialized countries and many developing countries—such as those in the GMS—is that that developing countries are often experiencing rapid growth in power demand. Unless these countries adopt expansion planning approaches such as IRP—that make a greater effort to consider energy efficiency, renewable energy, transboundary electricity trade, and internalization of externalities—the detrimental social and environmental impacts of expansion based almost entirely on large, long-lived, conventional generation projects may be both devastating and extremely difficult to reverse. They may also more exposed to risks such as social unrest, fuel price hikes, fuel supply constraints, etc.

Screening Supply-Side and Demand-Side Options

In 1994, the National Renewable Energy Laboratory (NREL) of the US considered how renewable energy should be modeled within an IRP.[91] This work recognized that one of the main obstacles to greater use of renewable energy in electricity grids is the reliance of utilities on models that were not designed to take account of the particular attributes of renewables. It thus aimed to identify the attributes and to describe methodologies that capture these attributes.

The principle attributes of renewable energy were listed in Table 3. The NREL paper then turned to wide-ranging activities typically applied to assess supply-side options, e.g., identifying options, assessing technical feasibility, cost estimation, screening, performance characteristics, site-specific characteristics, etc.

While some utilities use a model that optimizes the demand-side and supply-side options simultaneously, other utilities construct separate demand-side and supply-side plans and combine these into an integrated plan. Where a one-pass approach is adopted, it typically consists of three sequential steps:

(i) DSM options are screened in terms of cost-effectiveness relative to a set of marginal costs.

(ii) DSM impacts are used to determine net demand.

(iii) The generation expansion plan is optimized to meet net demand at minimum economic cost.

Researchers have found that this one-pass approach can yield a suboptimal optimization; instead, they recommend an iterative process in which the marginal costs arising from the supply-side plan are applied in the demand-side process, and the process repeated until marginal costs converge (Logan, Neil, and Taylor, 1994). In

[90] D. Nichols and D. von Hippel. 2000. *Best Practices Guide: Integrated Resource Planning for Electricity.* The Tellus Institute, for USAID. Boston.

[91] D. Logan, C. Neil, and A. Taylor. 1994. *Modeling Renewable Energy Resources in Integrated Resource Planning.* RCG/Hagler, Bailly, Inc., for NREL.

effect, the marginal costs are coordinating the separate demand-side and supply-side plans. Intermediate approaches include the iterative cost-effectiveness methodology and the iterative test for resource evaluation. Researchers have found, however, that the iterative cost-effectiveness methodology approach is biased against high capital cost, low operating cost resources such as wind and geothermal, and consequently they recommended the iterative test for resource evaluation approach. The iteration loop relating to marginal costs forms part of the typical IRP process flowchart is summarized in Figure 1 (p. 21).

Researchers also found that methods for integrating T&D planning with demand-side and supply-side planning had shortcomings, although developments in the intervening 25 years have made considerable advances to close the gap. The traditional approach was to undertake the T&D planning after the supply-side and demand-side planning have been completed. The marginal T&D capacity costs are then included when evaluating the cost-effectiveness of DSM options. The GMS countries are starting to catch up with countries such as the US, where there has been considerable effort over the past 3 or 4 decades, focusing on the introduction of DSM programs and applying distributed generation to defer T&D reinforcements. This focus requires greater cooperation between generation resource planners and system planners. DSM refers to the implementation of energy efficiency improvements and service management measures on the side of end users for optimizing energy systems overall.

A general point that should be made here is that international experience covers a great diversity of situations, which presents challenges to the drawing of clear lessons. For example, practices in France are different from those in the US. France has ceased using least-cost optimization to define long-term targets for renewable energy growth; instead, targets are defined using a top-down approach to comply with GHG reduction commitments made by the country, with network development following as a second step. Optimization studies in France tend to be based on prices observed on the market (capacity auctions, balancing markets, etc.), as they generally are in the US.

For the attributes of RES supply options to be fully taken into consideration, their aggregate effect on the output and operating costs of other generation sources should be considered through system-wide analyses. However, the incremental effect of a renewable energy project on system reliability and costs requires the incremental analysis of individual projects. Incremental analysis screens individual supply options for inclusion or rejection, whereas system-wide analysis provides the baseline for the incremental analysis since it is a key component of revenue requirement determination and financial forecasting. The operation simulation models used for system-wide analysis can also be used for incremental analysis, with the incremental effect of a supply option being the difference between with and without model runs. Since IRP with SEA seeks to encourage relatively small-scale renewable energy projects, as well as large-scale, the difference between with and without runs can be barely discernible. For such small projects, therefore, a marginal approach may be preferable, based on marginal costs determined using models capturing the stochastic nature of the RES.

Irrespective of whether a with and without approach or a marginal approach is adopted for the incremental analysis, this incremental analysis will still depend on system-wide analysis. Consequently, the aggregate impact of the renewable energy options needs to be modeled accurately—to the extent that the share of renewable energy in the plant mix may affect system marginal costs.

Marginal costs in power sector planning have two components: marginal capacity cost and marginal energy cost. Determination of the marginal energy cost requires a production simulation model and is typically one component of a suite.[92] Marginal capacity costs have three components—generation, transmission, and distribution—each of which can be determined in terms of the deferred capital expenditures. The marginal cost of generation capacity can also be determined based on marginal customer outage costs, using a generation reliability model. A further marginal cost for potential consideration is the marginal environmental cost, which is an area of interest to IRP and IRP with SEA.

Of the options available to system planners, energy efficiency is often the lowest-cost resource available. Also, it can help mitigate risks such as rising costs for reducing the impact of GHG emissions on global warming, or measures to reduce atmospheric and water pollution. Moreover, energy efficiency and DSM can be instrumental in deferring investment in T&D infrastructure. The State and Local Energy Efficiency Action Network from the US commented on IRPs in 2011.[93]

The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So, if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies.

Nevertheless, the treatment of energy efficiency in the US IRPs varies quite markedly from one state to another, which is unhelpful in determining best practice.

Several steps are proposed for establishing energy efficiency strategies:[94]

(i) Start with major targets within each subsector identified as having the greatest potential for energy efficiency to ensure the best impacts with the least intervention. These would include the largest energy consumers and industries offering the most immediate benefits from interventions, as well as those requiring more challenging measures.

92 PROMOD IV, Strategist, EGEAS, System Optimizer, MIDAS, AURORA, and Market Analytics are some of the models capable of undertaking production simulation and are used by several utilities in the US and by agencies around the world.

93 State and Local Energy Efficiency Action Network. 2011. *Using Integrated Resource Planning to Encourage Investment in Cost- Effective Energy Efficiency Measures.* USA.

94 United Nations Economic and Social Commission for Asia and the Pacific. 2011. *Guidelines for strengthening energy efficiency planning and management in Asia and the Pacific.*

(ii) Set up the baseline of energy consumption.

(iii) Identify the techno-economic energy saving potentials to set energy efficiency targets and prioritize actions based on their economic effectiveness.

(iv) Develop an implementation strategy allowable under available resources.

(v) Outline the mechanism for implementing an action plan for each subsector.

(vi) Collect relevant data and parameters that allow monitoring and evaluating the effectiveness of energy efficiency measures.

(vii) Plan the next cycle by widening the scope of activities, retaining high-performing actions, and examining and/or modifying the underperforming programs.

Some authorities suggest that best IRP practice includes a preliminary screening and assessment of the supply options that includes both qualitative and quantitative considerations (Nichols and von Hippel, 2000). The objective of this preliminary assessment is to screen out unpromising options on grounds of cost, resource characteristics, etc. There are various approaches used for the preliminary quantitative assessment, including

(i) life cycle costs—expressed in terms of Net Present Value (NPV) per kW and/or NPV per kWh;

(ii) levelized annual cost in relation to capacity factor—captures the variation in annual costs (annuitized capital, fuel, and O&M) for a range of capacity factors; and

(iii) simplified electricity production cost (footnote 14).

Best IRP practice in respect of the cost of supply-side options is—rather than adopting a single best-estimate value for each generation technology—to model a range of possible costs that factor in uncertainties in the range of cost inputs for each technology. In the lead up to the financial crisis of 2007–2008, the cost of oil, minerals, skilled labor, etc., escalated rapidly and generally confounded the forecasts of planners.

Internalizing Externalities

The US places many documented IRPs into the public domain. The profusion of these is in large because they are not prepared on a national basis and, instead, are prepared for the utilities that are required by state-based laws, regulations, and rules to undertake IRPs. From the perspective of determining best practice in IRP, the rules and regulations in these states vary appreciably. The West Coast utility, PacifiCorp—although commendable in respect of stakeholder participation and other issues such as energy efficiency and DSM—considers health assessments and other societal externalities to be outside the scope of their IRP. The Arizona Public Service, however, takes environmental costs into account when evaluating its resource plans. It uses a CO_2 adder, in anticipation that federal regulation of CO_2 will be introduced within the 15-year planning horizon of the IRP. It also uses adders (footnote 18) for SO_2, NOx, particulate matter, and water—water being of particular relevance in an arid state such as Arizona.[95] Returning to evidence presented in chapter 2, however, it is generally the case that IRPs in the US are conducted using financial costs from the utility's perspective, rather than using economic costs.[96] For example, the utility's interest in wind energy may focus on the tax credits available for that technology, or on CO_2 tax implications, rather than the economic cost savings from reduced GHG emissions and reduced health impacts due to reduced particulate matter emissions. The US IRPs are therefore of limited utility in terms of ascertaining best practice in the internalization of externalities.

Subsection 3.4 noted academic research indicating that there are few instances of planners internalizing external costs into IRP preparation—although TA 9003 has found that at least one state in the US, and—perhaps—South Africa, have incorporated external costs as adders, alongside the usual internal life cycle costs.

In contrast with the apparent dearth of examples of internalizing external costs, subsection 3.4 identified several published works that collect externality values for the various power generation technologies.

In conclusion, therefore, best practice is considered by TA 9003 to be the adoption of the approach used by the Arizona Public Service, but also capturing monetized externality costs for other critical social and environmental impacts, and not solely those relating to emissions.

Optimizing Candidate IRPs

The experience of both EGAT in Thailand and the Institute of Energy in Viet Nam is instructive, that the power and flexibility of the software package used to optimize candidate IRPs needs to keep pace with the demands of a modern IRP. It is not the role of TA 9003 to recommend specific software tools for each of the GMS countries; modern packages typically have good flexibility but also have strengths and weaknesses. Each country should select a software package that is a strong match to its unique physical characteristics and planning goals.

Research undertaken by TA 9003—including the studies reported in subsection 6.1—suggests that packages that incorporate a mixed-integer linear programming (MILP) optimization routine perform reasonably well in terms of speed and power. OptGen, PLEXOS, BALMOREL, and CAPRICORN are among the suites that incorporate MILP and have been applied in the GMS countries.

95 Since compliance with environmental regulations forms one of the key goals in any IRP in the US, it is therefore considered good practice in that country to consider future regulations that might reasonably be expected.

96 Utilities in the US also tend to optimize with the objective function of minimizing the present value of revenue requirements, rather than the present value of net economic costs.

Assessment of Candidate IRPs

Before the various levels of management can recommend a preferred IRP—and contingent IRPs— they need to undertake reviews concerning their goals, regulatory constraints, planning criteria, etc. To undertake such reviews, which will—under best practice—be exposed to extensive stakeholder scrutiny, they need to be armed with a thorough assessment of the candidate IRPs developed under the process.

The number of well-documented IRPs from the US is extensive, and these IRPs are typically simplified to meet specific regulatory requirements.[97] In one area in particular, however, an assessment of international best practice can learn useful lessons from this literature. Individual US states often set a wide range of targets and objectives for the individual utility. These may include consideration of renewable energy targets; energy efficiency and DSM initiatives; brownfield sites, etc., and originate from federal and state legislation, federal and state regulators, and stakeholder consultations.

As with many aspects of preparing an IRP—and especially an IRP with SEA—analytical methodologies and software models are generally incapable of receiving all the constraints, and all the parameter values, risks, and uncertainties that will yield a definitive, optimized expansion plan. Even if standardized models were available to undertake such computations, the output from the exercise would be unlikely to satisfy all stakeholders to the IRP. Essentially, some of the goals set for an IRP can often conflict with each other or lead to unacceptable environmental and/or financial risks. The challenge for the utility is therefore to ensure that candidate IRPs addressing the goals—in various combinations—are thoroughly assessed, and their relative merits and de-merits quantified. An IRP also must consider risks and uncertain outcomes. Such a process thus aims to satisfy the legal and regulatory requirements for the highest standards of transparency and good governance. The techniques adopted by many US utilities qualify as worthy of consideration as best practice in respect of IRP candidate assessment.

PacifiCorp's 2017 IRP

PacifiCorp's 2017 IRP is a well-documented resource relevant to this discussion.[98] The following extract on the role of PacifiCorp's IRP helps to set the scene.

> "PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest." The main role of the IRP is to serve as a road map for determining and implementing the company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business

---

97 In PacifiCorp's 2017 IRP, referenced in footnote 98, the following quote provides strong evidence on the limitations of IRPs in the US: "Generally, PacifiCorp considers health assessments and other societal externalities to be outside the scope of the IRP, which focuses on the economic costs of various resource decisions including direct costs to serve our customers."

98 PacifCorp. 2017. *2017 Integrated Resource Plan.* Portland, Oregon.

goals, and uncertainty. As a business planning tool, it supports informed decision making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting RFP bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources."

To ensure full consideration of their goals and constraints, PacifiCorp used a system optimizer[99] to produce 43 unique resource portfolios, spanning a range of planning assumptions. Risk analysis that considered stochastic-driven risk metrics was then undertaken on each of these optimized portfolios, with three scenarios for natural gas prices and two CO_2 emission limit scenarios. A further 24 sensitivity cases were developed to address stakeholder comments received during public consultations. The results from the Monte Carlo stochastic simulation for each unique resource portfolio were presented graphically in the IRP report, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. Three screening stages were applied. Within each stage, each portfolio was compared based on cost-risk metrics, and the least-cost, least-risk portfolio was chosen. The final screening stage considered not only the draft preferred portfolio, but also significant indicators from all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. PacifiCorp thus applied comprehensive modeling involving cost and risk evaluations, and portfolio comparisons based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions, and other criteria, to produce a preferred portfolio.

Conclusions of Best Practice

Screening Supply-Side Options

An intrinsic quality of an IRP or IRP with the SEA approach is that they consider the inclusion of a wide range of technologies and sizes of supply-side projects as candidates. These options will have principle attributes such as where they contribute to the daily, weekly, and annual load cycle—i.e., baseload, mid-merit, or peaking; low GHG emissions characteristics; energy storage; etc. Each project will also have associated social and environmental impacts—and related external costs—that may have a locational dimension, e.g., the external cost of pollution from a thermal plant will vary with its degree of proximity to population centers.

To reduce the workload further along the IRP preparation process, a preliminary screening of these options should remove unsuitable options based on the levelized cost of energy, resource considerations, technical uncertainties, etc. Screening curve analysis is a useful tool at this stage in the process. The preliminary screening should not be too fine, however, since more rigorous analysis—undertaken subsequently—takes fuller account of the options' attributes.

[99] PacifCorp's optimizer minimizes operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints.

The approach adopted for Thailand's Alternative Energy Development Plan (AEDP)—elaborated in Appendix 3 Section A3.3—probably has relevance to other GMS countries in that the screening process for renewable energy technologies focuses on the fact that agricultural residues are of greatest abundance in rural areas where transmission constraints are also very likely to apply. The approach takes account of life cycle costs for each technology while capturing externalities such as GHG reduction and employment creation, to establish the merit order for each renewable energy technology. The approach is applied on a spatial basis that takes account of resource availability, electricity demand, and transmission capacity. Targets in each area and for each technology are thus established.

The levelized cost of renewable energy is periodically estimated by agencies such as IRENA by regions of the world. Bloomberg New Energy Finance is another reliable source. However, there are also significant regional variations in the LCOE due to variations in supply volumes and cost structures, renewable energy resources, and the cost of capital.

Screening Demand-Side Options

Identifying best practice in evaluating demand-side options is not straightforward. Many countries recognize that EE&C is the first fuel, and although policies are formulated, action plans developed, etc., progress is often much slower than anticipated, especially in rapidly expanding developing countries such as those in the GMS.

A fundamental principle of IRP is that demand-side options are treated equally with supply-side options. The arbiter on this is the marginal economic cost of the measures. An initial screening of the options can be undertaken using a conservative estimate of the marginal cost. Best practice would appear to be the further assessment of demand-side options simultaneously with those of the supply-side options, using the optimization software and integrating to a convergence on the marginal cost.

Internalizing Externalities

The internalizing of externalities in IRPs does not appear to be widely practiced. Although there are approaches that enable externalities to be factored into an IRP—and particularly an IRP with SEA—TA 9003 does not consider that these approaches merit good practice status. Good practice appears to be the determination of the costs of individual externalities, referencing methods, and values from detailed studies in the public domain, augmented by consideration of local characteristics. These external costs can be incorporated into the expansion optimization modeling by using the external costs as an adder to the internal life cycle costs for each generation technology. Some utilities in the US adopt this approach. Where different methodologies produce widely varying values for external costs—and which may have a critical bearing on the optimized expansion plan—alternative scenarios can be undertaken. Where multicriteria analysis (MCA) is used to evaluate multiple candidate IRPs, the external costs can be discussed with stakeholders, during consultations, to establish relevant weightings.

South Africa and Thailand—and possibly others—adjust CO_2 emissions by capping them at the level in their NDC commitments. While this constraint may ensure that the NDC commitments are not breached in any year, it may not be enough—by itself—to ensure that an expansion plan with the least economic cost is yielded by the optimization process, which could require the cost of CO_2 in $/kWh to be added to individual generation candidate plant costs. Nor does it guarantee that the plan will minimize CO_2 emissions. Renewable energy generation technologies such as photovoltaics plus storage are increasingly becoming competitive with conventional thermal, and more so when external adders are applied to all technologies and thus penalizing conventional thermal much more than photovoltaics plus storage. If recent trends continue, and if the full economic costs are included in the optimization process, system expansion at least economic cost will start to include more renewable energy capacity than the current NDC commitments would require.

Optimizing Candidate IRPs

Industry best practice is to optimize network expansion using software that includes MILP. Speed and power are important because many scenarios should ideally be considered due to the range of objectives that planners must consider. For systems like those in the GMS, the software should have the capacity to deal with the following:

(i) hydrothermal systems with large numbers of existing and candidate hydropower projects that may form part of a cascade;

(ii) multipurpose hydropower projects, whose operation for power generation may be constrained by requirements such as water supply, irrigation, or minimum releases to safeguard fisheries and downstream riparian areas;

(iii) spatial representation, to ensure that transmission reinforcement investments are captured to avoid or minimize transmission constraints; and

(iv) large numbers of candidate projects, including small and large intermittent renewable energy projects.

Assessment of Candidate IRPs

Good practice IRPs are well removed from the traditional least-cost expansion approach of grouping a set of candidate projects and implementing the optimized plan produced by the software package. A modern IRP must consider a wide range of goals and objectives, some of which may be conflicting, e.g., least-cost and meeting NDC commitments, or meeting NDC commitments and not building dams and reservoirs in sensitive ecosystems. Good practice is to develop scenarios that explore each objective and combinations of objectives; the optimized plan under each scenario is a candidate IRP. To choose a preferred IRP from these candidate IRPs—and maybe also a contingency IRP—requires separate consideration.

Good practice in assessing the candidate IRPs and selecting the preferred IRP is to apply MCA or, sometimes, multiple attribute analysis. MCA is a sub-discipline within operations research and various—sometimes complex—approaches can be applied. At a simplistic level, the decision makers will establish a set of criteria that map closely with the goals and objectives set for the IRP. MCA then requires that each candidate IRP is scored against each of the criteria, and weighting is applied to each score—since some criteria may be judged as more crucial than others—to establish a total score for each candidate IRP. The potential issue, here, is that the selection of criteria, the scoring, and the applied weightings can be highly subjective.

To minimize the subjectivity in MCA—and as mentioned in subsection on internalizing externalities—good practice is for the criteria and weightings to be established early in the IRP preparation process, through a rigorous and transparent stakeholder consultation process.

6 Modeling for Integrated Resource Planning in Power Sector Planning

6.1 Integrated Resource Planning Modeling in Viet Nam

IRP modeling has been investigated in detail in this study regarding the case of Viet Nam, to explore the potential application of enhanced modeling techniques against a baseline of the analysis carried out in the current PDP process. IRP modeling for Viet Nam's PDPs is undertaken by the Institute of Energy, which uses Strategist and Power Development Planning Assistant Tool (PDPAT) II[100] for this purpose. As with EGAT in Thailand, the Institute of Energy version of Strategist is around 12 years old and has never been updated. Donors supported PDPAT II under a project some years ago. Strategist is not the most recent available and is understood to have struggled with the modeling for Revised PDP VII. However, although optimization runs using Strategist can take extended periods, the results are not significantly different from those produced by a more current and powerful optimization model, as detailed in subsection 6.1.

Modeling the Viet Nam system is challenging for several reasons: it has a complex power system with major demand centers at the extremes of a very long and narrow transmission network, and with significant hydropower generation plants that have both seasonal inflow characteristics and multipurpose release constraints. Also, national development policies require energy efficiency and renewable energy opportunities to be maximized to meet CO_2 reduction targets and other sustainability goals.

6.2 Application of Enhanced Modeling Techniques

Background

TA 9003 investigated the technical feasibility of considering a range of additional factors (externalities) when mathematically optimizing power system expansion plans. The investigation was conducted using the Vietnamese power system as an example and

[100] Power Development Planning Assistant Tool (PDPAT) is a power system analysis software package that was developed by Tokyo Electric Power Company Holdings (TEPCO) of Japan. TEPCO has used and revised PDPAT to analyze power supply capability and system operation costs as a routine part of its planning process. Source: Corporate information. TEPCO. https://www.tepco.co.jp/en/corpinfo/consultant/benefit/6-power-e.html.

based on the data employed by the Viet Nam Institute of Energy when deriving the Revised PDP VII, covering 2015 to 2030. The objective of the investigation was not to produce a new PDP for Viet Nam, since this would have required updating the data set employed, including demand forecasts, candidate project costs, and characteristics.

The investigation uses the CAPRICORN expansion planning software, which can be used in combination with the AQUARIUS program used for optimizing the operation of integrated water and electricity supply systems.[101]

A brief history of how computer programs for mathematically optimizing power system expansion plans have developed since the 1970s, the factors promoting the development of CAPRICORN and its principal attributes are given in Section 6.5.1.

The CAPRICORN model of the potential Vietnamese power system includes the representation of what the Vietnamese call 77 hydropower plants (of which 6 are located in the Lao PDR, 4 are pumped storage, and 10 are small hydropower composites); 141 thermal plants (which include 84 coal-fired, 23 gas-fired, 13 wind-powered, 8 biomass-fed, 6 solar-powered, 4 nuclear-fueled, 2 oil-fired, and 1 representing imports from the PRC); 268 transmission lines; 41 transmission nodes; and 7 electricity demands.

While existing and candidate large hydropower and thermal plant are identified by name, installed capacity, and relative location within the Revised PDP VII reports—according to the Institute of Energy—details of individual project investment costs and construction periods were not input to the Strategist optimization process. In certain cases, the application of unit investment costs may be judged to be acceptable, e.g., when applied to generic (i.e., non-location specific) plants. However, it is unusual for such an approach to be followed when dealing with hydropower plants of significant size, given that their technical and cost characteristics are intrinsically unique. Also, application of the same unit investment cost and operating costs for different types of thermal plant or fuel types, regardless of location, means that significant differences in fuel transport and network connection costs will effectively be ignored within the mathematical optimization process.

For modeling purposes, renewable energy plants were split into four categories, i.e., small hydropower, wind (onshore), solar photovoltaics, and biomass-fed plants. Regional candidate plants were modeled as being generic, and subject to maximum annual capacity increments to reflect limits on technology penetration.

Regional sales of electricity are forecast to grow substantially, although at slightly decreasing rates, over the 2015–2030 planning period. Equivalent figures for generation requirements were some 12% higher and, within the CAPRICORN models,

[101] CAPRICORN and AQUARIUS are software packages developed by Power & Water Systems Consultants Ltd. (PWSC), UK.

this loss factor was applied to transmission lines supplying each electricity demand. Three load blocks were used to represent peak, mid-range, and baseload demands in each (annual) plan step and—following inspection of the daily load curves contained within the Revised PDP VII reports—the daily durations of these blocks were set to 4, 18, and 6 hours respectively. In the absence of detailed forecasts, minimum loads were set equal to 40% of the forecast peak values.

CAPRICORN allows differential benefits to be assigned to supplies of electrical energy so that, within the optimization process, an account can be taken of revenue streams associated with meeting both domestic and export demands. For the current study, a common value of $80/MWh was assigned for the benefits from supplying the North, Centre, and South demands, and for exports to Cambodia, based on the estimated average domestic tariff.

A penalty for non-supply (cost of unserved energy) equal to 10 times the average domestic tariff was universally applied, i.e., $800/MWh ($0.80/kWh).

Eight optimization runs of CAPRICORN were undertaken, and these are described in detail in the following subsections.

In each run, CAPRICORN optimized the outputs of each generation plant and the flow in each transmission line included in the system for

(i) each peak, mid-range, and baseload block;

(ii) each year of the 16-year planning period from 2015 to 2030; and

(iii) each hydrological condition (HC) analyzed.

For Runs 2 to 8, the program also optimized the commissioning years of each generation plant and each transmission line that is not used to connect a specific generation plant to the network.

Run 1—Revised PDP VII Expansion Plan

Run 1 simulated the performance of the expansion plan constituted by Revised PDP VII, i.e., the commissioning dates of all generation plants were fixed, as well as the increases in the inter-regional transfer capacities in 2021.

The installed capacity margins were seen to be surprisingly high when compared with the standard practice of requiring, say, a minimum of 10% above peak load or the largest-generating unit in the system.

Similarly, firm energy availability, based on an assumed 50% reduction of the average hydropower energies, comfortably exceeded the forecast demands in all years.

Factors contributing to such high margins include that, when establishing Revised PDP VII, it may have been deemed to be necessary to

(i) give little or no capacity credit to wind and solar power plants due to the intermittent nature of their outputs,

(ii) compensate for inter-regional transmission constraints, and

(iii) take account of historic failures to implement previous power development plans in a timely fashion.

Analysis showed the following results under Revised PDP VII:

(i) The introduction of new large hydropower plants will be virtually complete by the year 2020, although investment in small and pumped-storage hydropower continues.

(ii) There would be major investments in domestic and imported coal-fired plants, in the North and South, respectively.

(iii) Wind and solar generation capacity would increase steadily from 2020, with the first nuclear plant scheduled to enter operation in 2028.

(iv) High and unevenly distributed investment costs increase, peaking in 2016, due to substantial investments in large hydropower plants being constructed simultaneously.

(v) There are relatively low operating costs.

(vi) Center–North transfers are limited by the maximum transfer capacity, even after the increase from 2,000 MW to 3,600 MW planned to be available from 2021.

(vii) CO_2 emissions will steadily increase over the 2015–2030 planning period and be almost six times greater in 2030 than in 2015.

The resulting annual CO_2 emissions were assumed to correspond to the business-as-usual (BAU) case concerning Viet Nam's commitments under the Paris Agreement.

Run 2—10% Capacity Margin, 5% Energy Margin, HC1 Very Dry Hydrology

Run 2 optimized the expansion of the Viet Nam system subject to the maintenance of a 10% target installed capacity margin and a 5% firm energy margin, i.e., assuming that the firm (HC1) hydropower plant energies were 50% of the average (HC3) values. The results showed the following for the CAPRICORN optimized plan:

(i) The target capacity margin of peak load plus 10% was met in each year after 2022.

(ii) Installed capacities were substantially lower than those for Run 1 (Revised PDP VII), once the influence of the plant already committed in 2015 was removed.

(iii) The firm energy plus 5% margin was met in all years except 2024–2025, indicating that, as usual, when there is a significant renewable energy component, systems are energy-constrained rather than capacity-constrained.

(iv) When compared with Run 1, an absence of wind, solar and biomass renewables, and no pumped-storage hydropower or nuclear plants are to be commissioned.

(v) In 2030, the number of domestic coal plants in the North would be virtually unchanged, but the capacity of imported coal plants in the South would be somewhat lower than with Run 1.

(vi) Maximum load flows from Centre–South are larger than those associated with Run 1, no increase to the current Centre–North capacity of 2,000 MW is envisaged, and the planned Centre–South capacity increase is delayed until 2022 rather than 2021.

(vii) A total investment cost of $100.4 billion or almost 50% less than the figure of $147.2 billion, was calculated for Run 1.

(viii) There is a sharp dip in annual investment expenditures in the years 2013, 2014, and 2015, as costs of the plant already committed in 2015 taper, before rising steadily and reaching a maximum of $12.1 billion in 2026.

(ix) There is a slightly higher total operating cost of $12.9 billion, compared with $12.2 billion for Run 1.

(x) The total net cost (i.e., investment, operating, and unserved energy costs minus supply benefits) was –$275.8 billion for Run 2.

(xi) Total CO_2 emissions of 3.149 billion metric tons, i.e., slightly higher than those of 2.924 billion metric tons for Run 1.

The results reflect a significant reduction in total capacity installed, but also the high costs assigned to non-hydropower renewable energy plants relative to more conventional forms of generation in 2015 and formed the reference case against which the results of all subsequent runs were compared.

Run 3—Run 2 with Maximum Annual CO_2 Emission Limits

Run 3 was used to confirm the feasibility of imposing maximum annual CO_2 emission limits commensurate with a Paris Agreement obligation that Viet Nam did not support:

(i) The required installed capacities would need to be greater than for Run 2.

(ii) This was achieved by introducing wind, solar, biomass, and nuclear capacity.

(iii) Close compliance with the annual target CO_2 quantities was imposed.

(iv) While the firm energy always exceeded the forecast energy demand, in the years 2025–2028 and 2030 it fell below the target criterion of the forecast energy demand plus 5%.

(v) The total investment costs of $108.4 billion showed an 8% increase over the $100.4 billion obtained with Run 2.

(vi) Supply deficits were recorded in 2015, 2016, and 2030, illustrating the existence of trade-offs between supply security and meeting the CO_2 emission targets imposed.

(vii) The total net cost of –$251.2 billion was $24.6 billion more than the equivalent figure of –$275.8 billion associated with Run 2 and could be interpreted as being the cost of complying with the CO_2 emission constraint imposed.

Run 4—Run 2 with Annual Capital Investment Limits

Run 4 was designed to illustrate the feasibility and implications of imposing limits on annual investment costs, since it is understood that difficulties have been encountered with the timely implementation of previous Vietnamese PDPs. Based on the results obtained for Run 2, an annual limit of $10 billion was imposed for illustration. The results showed that

(i) the installed capacity and firm energy margins were satisfied by the optimized solution;

(ii) compared with Run 2, the CAPRICORN optimization reduced the annual investment costs in 2025, 2026, and 2027 to the limit imposed, while increasing the costs in the years 2021–2024;

(iii) at $100.3 billion, the total investment cost associated with Run 4 was almost identical to that for Run 2, suggesting that the application of such constraints could result in expansion plans with more manageable investment requirements, without incurring a significant financial penalty in terms of total expenditure, and

(iv) annual CO_2 emissions were only very slightly higher than for Run 2.

Run 5—Run 2 with Strategic Demand Management Measures

Run 5 was designed to demonstrate the application of realistic and pragmatic, rather than investigative, planning criteria when optimizing the expansion of hydrothermal power systems. Rather than only considering average (HC3) hydrological conditions within the objective function, an explicit account was taken of system operation under very dry (HC1) conditions when accompanied by a quantified reduction in electricity supplies, i.e., the imposition of strategic DSM measures.

As indicated in subsection 4.2, the severe drought experienced by Viet Nam in 2010 is understood to have resulted in stream flows of only around 50% of their average values. In the absence of further data, the energy availabilities of this study for both large and small hydropower plants under HC1 were therefore assumed to be 50% of their average (HC3) values.

For countries significantly reliant on hydropower, it can be economically justifiable to plan for the imposition of strategic demand management measures in the event of low-flow (drought) periods including, for example, a repetition of the most extreme historic events.

Accordingly, it was assumed that the reduced hydropower availabilities associated with HC1 would be accompanied by a 30% reduction of peak load and a 20% reduction of the amount of energy supplied. For operating cost, supply deficit, and benefit-weighting purposes, HC1 was assigned a 5% probability (i.e., 1 in 20 years) and HC3 a probability of 95%.

The main results of this optimization were as follows:

(i) there are similar annual installed capacities to those obtained for Run 2, and comfortably above the 10% margin as in Run 2;

(ii) available system firm energies are slightly less than the forecast (HC3) demand in 2024 and 2025;

(iii) energy contributions from different plant types are virtually identical to those for Run 2 under the same hydrological condition;

(iv) under HC1, the hydropower energy contribution is, as expected, effectively halved and the coal and gas plant outputs increased in compensation;

(v) total energy generated is reduced by 20% under HC1, due to the imposition of the demand management measures;

(vi) use of inter-regional transfer capacity appears to be increased under HC1 and HC3 compared with Run 2; and

(vii) annual CO_2 emissions under HC1 are less than those under HC3, with the 20% reduction in energy supplied more than offsetting the lower availability of hydropower plant energies.

These results confirmed the importance of considering extreme conditions when optimizing integrated power system expansion plans.

Run 6—Run 2 with Selection between Mutually Exclusive Demands

Run 6 was designed to investigate whether—as part of the mathematical optimization of power system expansion plans—it is possible to select between alternative mutually exclusive electricity demands. For example, between forecast demands and those reduced by the implementation of energy efficiency measures, but having associated investment costs.

In the event, the optimization selected the forecast demands for each region rather than the reduced energy efficiency demands. In other words, the cost of implementing the energy efficiency measures was outweighed by the benefits associated with meeting the higher forecast demands.

Therefore, the following observations are based on the results corresponding to the case where the energy efficiency demands, and their associated investment costs, are imposed:

(i) Installed capacities are only slightly lower than for Run 2, commensurate with the slightly reduced energy efficiency demands imposed.

(ii) The available firm energy was below the target of energy demand +5% in the years 2023–2026.

(iii) A total investment cost of $99.7 million, which is only slightly less than the $100.4 million for Run 2, reflects the small impact of the energy efficiency measures imposed on the demands (and consequential reduction of investment in additional capacity).

(iv) Whereas investments in 2030 are zero for all other runs, in this case, the value of $26 million corresponds to the costs of implementing the energy efficiency measures in that year.

(v) The net costs of –$274.7 billion are marginally lower than the figure of –$275.8 billion corresponding to Run 2. This is consistent with the CAPRICORN optimization selecting the forecast demands rather than the energy efficiency alternatives, to maximize total net costs.

(vi) Annual CO_2 emissions are marginally lower than for Run 2 due to the slightly lower demands imposed.

Run 7—Run 2 with Lower Non-hydropower Renewable Energy Capital Costs

Run 7 was designed to establish how reductions in the investment costs associated with non- hydropower renewable energy plants such as wind and solar might influence the development of the Vietnamese power system and contribute to reducing future levels of CO_2 emissions.

Most data used for this investigation were understood to have been employed when deriving the Revised PDP VII in 2015 and hence pertains to that year or earlier.

The optimization run showed the following results:

(i) the target installed capacity margin of peak demand plus 10% was satisfied in all years of the expansion planning period;

(ii) when compared with the results of Run 2 there was a significant increase in the installation of solar plants, but not wind power;

(iii) compared with Run 2, there was a reduction in imported coal-fired plant capacity and in the amount of small hydropower installed by 2030;

(iv) there was a 12% reduction in total investment costs compared with Run 2, due to the significant reduction in the costs of solar plant installation; and

(v) at 3.063 billion metric tons, the total CO_2 emissions were slightly lower than the corresponding figure of 3.149 billion metric tons for Run 2.

Run 8—Run 2 with Tighter Annual CO_2 Constraints

The objective of Run 8 was to investigate the imposition of annual CO_2 emission constraints commensurate with Viet Nam's higher (conditional) obligations under the Paris Agreement, combined with contemporary data relating to non-hydropower renewable energy generation.

The conditional obligation equated to a 9.8% reduction in power CO_2 emissions relative to the BAU case constituted by the implementation of Revised PDP VII (Run 1). The results of this optimization showed that:

(i) the annual CO_2 emission limits were closely matched by the optimization procedure;

(ii) this was achieved by commissioning substantial amounts of zero-emission solar, wind, and nuclear capacity, displacing coal and gas plants scheduled to be commissioned under Run 2;

(iii) there was a significant increase in total investment costs compared with Run 2, i.e., $120.9 billion compared with $100.4 billion;

(iv) as with Run 3, there was a trade-off in terms of supply security, with optimized unserved energies of 4.2% of the system energy demand in 2015, 2.7% in 2016, and 1.0% in 2030;

(v) the scheduled 2021 increase in Centre–North transfer capacity to 3,600 MW would be reduced to 2,729 MW in 2029, while the Centre–South capacity of 5,100 MW would not be increased; and

(vi) mainly as a result of the increased investment expenditures, the total net costs would be –$242.9 billion compared with the equivalent figure of –$275.8 million associated with Run 2.

Results Summary

Details and results of all the CAPRICORN runs undertaken are tabulated in Table 8 which also includes summary figures illustrating

(i) how—as expected—reduced CO_2 emission limits and lower investment costs increase the penetration of non-hydropower renewable energy plants in the optimized expansion plans,

(ii) that systems with large hydropower and other renewable energy plant components are usually energy- rather than capacity-constrained,

(iii) the average energy generated by each type of plant in 2030,

(iv) the annual investment costs associated with each run, and

(v) the annual CO_2 emissions in million metric tons for each run.

These results are presented graphically in Figure 7 to Figure 10.

Figures 7 and 8 show that, as might be expected, reduced CO_2 emission limits and lower investment costs increase the penetration of non-hydropower renewable energy plants in the optimized expansion plans. It can also be noted that the total installed capacities vary since systems with significant amounts of renewable energy plants are energy-constrained rather than capacity constrained.

Figure 9 shows the annual investment costs associated with each run.

Figure 10 shows the annual CO_2 emissions in million metric tons for each run.

Subsection 6.3 lays out the key conclusions drawn from the investigations and recommendations for future mathematical optimization of PDPs within the GMS and elsewhere.

Table 8: **Summary Details of CAPRICORN Runs**

RUN NUMBER	1	2	3	4	5	6	7	8
Run description	Simulation of Power Development Plan VII Revised.	Optimization subject to target energy and capacity margins.	Optimization with CO_2 emissions constrained to be 4.4% less than for Run 2.	Optimization with annual investment cost totals constrained to $10 billion.	Maximum HC1 hydropower plant energy outputs reduced to 50% of average (HC3) values. Peak load electricity supplies reduced by 30% and energy by 20% (DSM).	Electricity demands reduced by the imposition of quantified energy efficiency measures and associated investment costs.	Application of updated wind, solar, and biomass cost and performance parameters.	Optimization with CO_2 emissions constrained to be 9.8% less than for Run 2 and updated renewable energy plant values.
Objectives	To establish associated investment and operating costs, supply reliabilities and CO_2 emissions.	Compare optimized plan with Revised PDP VII.	To demonstrate the functioning of emission constraints and show additional costs compared with Run 2.	To demonstrate the functioning of annual cost constraints to smooth funding requirements.	To demonstrate the ability to take account of different hydrological conditions and defined demand management measures.	To demonstrate incorporation of alternative demands that reflect energy efficiency measures and their associated investment costs.	To show the influence of updated technical characteristics and costs of wind, solar, and biomass-based generation.	To demonstrate the effects of lower-emission targets and updated costs of renewables.
CO_2 emissions constrained	No	No	Yes	No	No	No	No	Yes
Annual investment totals constrained	No	No	No	Yes	No	No	No	No
Hydrological conditions considered	HC3	HC3	HC3	HC3	HC1 and HC3	HC3	HC3	HC3
Commissioning dates optimized	None	Generation plants and transmission lines	Generation plants and transmission lines	Generation plants and transmission lines	Generation plants and transmission lines	Generation plants, transmission lines, and electricity demands	Generation plants and transmission lines	Generation plants and transmission lines

continued on next page

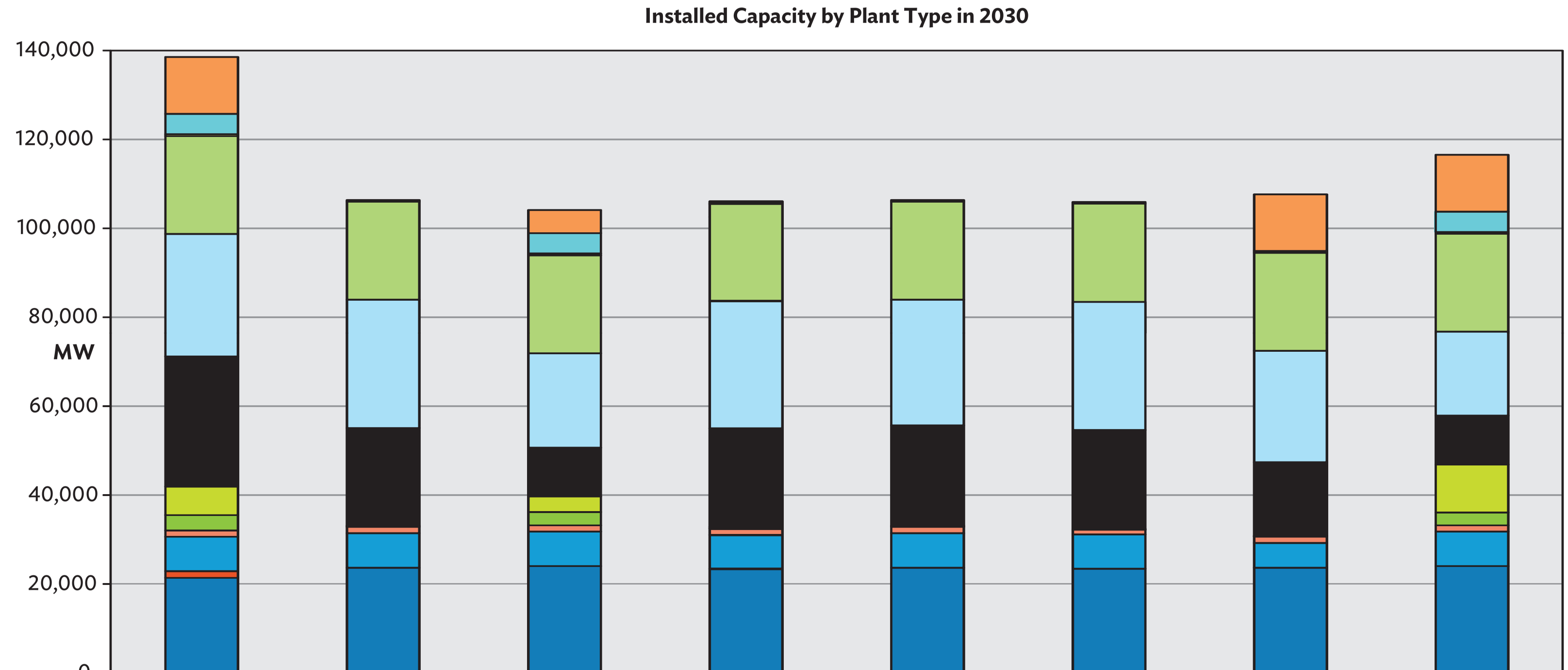
Table 8: *continued*

RUN NUMBER	1	2	3	4	5	6	7	8
Plant outputs and transmission line load flows optimized for each hydrological condition, load block, and plan year	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Firm energy margin	n/a	5%	5%	5%	0%	5%	5%	5%
Installed Capacity Margin	n/a	10%	10%	10%	0%	10%	10%	10%
Expected Result as compared with Run 2	n/a	Reduced investments as a result of lower installed capacity and energy margins.	Increased costs and the amount of renewable generation.	Annual investment costs <= to set limits. Increased total costs.	Closer alignment with meeting forecast demands. Reduced emissions under HC1.	Lower total costs if Energy Efficiency (EE) demands are selected.	Increased scheduling of renewable energy plants.	Increased investment costs and scheduling of renewable energy plants rather than coal and gas.
Result achieved	n/a	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Comments	Large energy and installed capacity margins. Large variations in annual capital costs.	Substantial reductions in total costs.	CO_2 emissions very close to target quantities.	Annual investment costs <= set limits.	Demonstrates the application of more focused planning criteria.	Reduced energy efficiency demands not selected. Total net cost slightly greater than for Run 2 if imposed.	Solar preferred to wind.	CO_2 emissions very close to target quantities.
Decision variables	15,289	20,483	20,483	20,483	39,247	20,497	20,756	20,756
Constraints	20,905	26,615	26,615	26,615	52,600	26,616	26,921	26,977
Investment costs ($ million)	147,201	100,361	108,413	100,361	100,616	99,754	88,093	120,994
Operating costs ($ million)	12,285	12,942	12,291	12,975	12,658	12,845	12,927	12,179
Supply deficit costs ($ million)	0	0	15,641	0	0	0	0	11,898
Supply benefits	-389,145	-389,145	-387,580	-389,145	-385,275	-387,390	-389,144	-387,927
Total net costs ($ million)	-229,650	-275,841	-251,234	-275,808	-272,001	-274,790	-288,123	-242,856

CO_2 = carbon dioxide, HC = hydrological condition, PDP = power development plan.

Source: Ricardo Energy & Environment.

Figure 7: **Summary Results—Installed Capacities in 2030 by Plant Type**

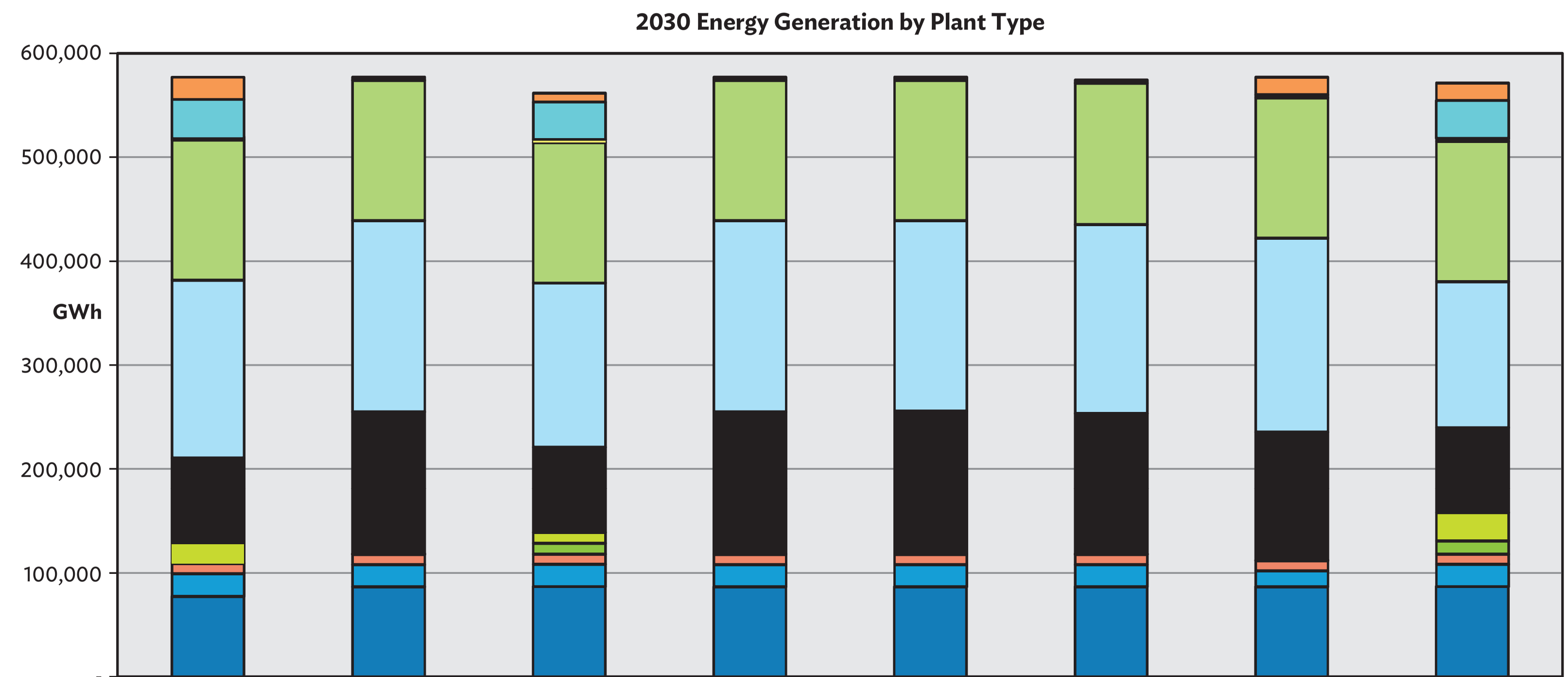


	Run 1	Run 2	Run 3	Run 4	Run 5	Run 6	Run 7	Run 8
SOLAR	12,765	-	5,199	-	-	-	12,765	12,765
NUCLEAR	4,600	-	4,600	-	-	-	-	4,600
IMPORT	400	400	400	400	400	400	400	400
CCGASDOM	22,009	22,030	22,030	22,030	22,030	22,030	22,030	22,030
COAL-DOM	27,557	28,855	21,222	28,855	28,266	28,604	25,066	18,865
COAL-IMP	29,285	21,971	10,985	21,971	22,560	21,703	16,518	10,985
WIND	6,421	180	3,504	180	180	180	180	10,800
BIOMASS	3,454	109	2,995	109	109	54	54	2,895
OIL	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406
S HYDRO	7,755	7,755	7,755	7,755	7,755	7,755	5,566	7,755
PS HYDRO	1,500	-	-	-	-	-	-	-
HYDRO	21,408	23,698	24,058	23,698	23,698	23,698	23,698	24,058

MW = megawatt.

Source: Ricardo Energy & Environment.

Figure 8: **Summary Results—Generated Energies in 2030 by Plant Type**

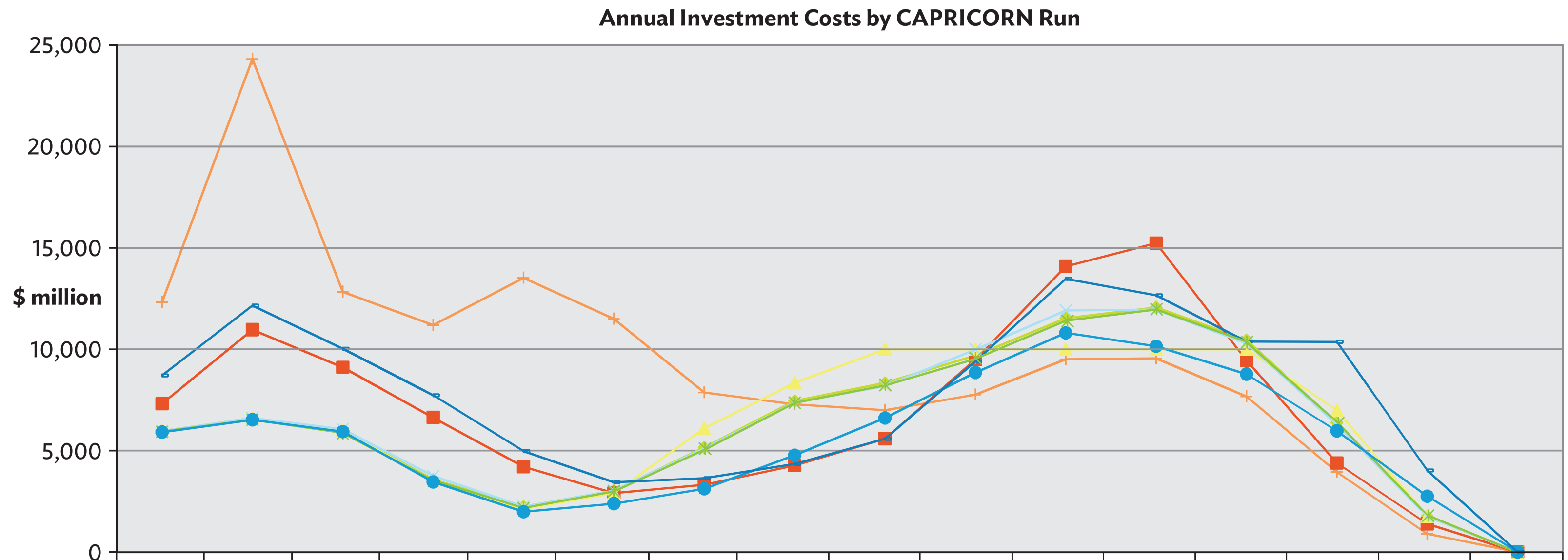


	Run 1	Run 2	Run 3	Run 4	Run 5	Run 6	Run 7	Run 8
SOLAR	20,637	-	8,445	-	-	-	16,773	16,773
NUCLEAR	36,266	-	36,266	-	-	-	-	36,266
IMPORT	2,920	2,920	2,920	2,920	2,920	2,920	2,920	2,920
CCGASDOM	134,959	135,088	135,088	135,088	135,088	135,088	135,088	135,088
COAL-DOM	171,325	183,997	158,018	183,997	183,137	182,476	186,641	140,465
COAL-IMP	82,886	136,271	81,794	136,271	137,130	134,752	122,995	81,794
WIND	19,214	536	10,481	536	536	536	394	27,199
BIOMASS	-	159	10,510	159	159	79	236	12,680
OIL	9,850	9,850	9,850	9,850	9,850	9,850	9,850	9,850
S HYDRO	21,459	21,459	21,459	21,459	21,459	21,459	15,382	21,459
PS HYDRO	-	-	-	-	-	-	-	-
HYDRO	77,494	86,731	86,962	86,731	86,731	86,731	86,731	86,962

GWh = gigawatt-hour.

Source: Ricardo Energy & Environment.

Figure 9: **Summary Results—Annual Investment Costs**

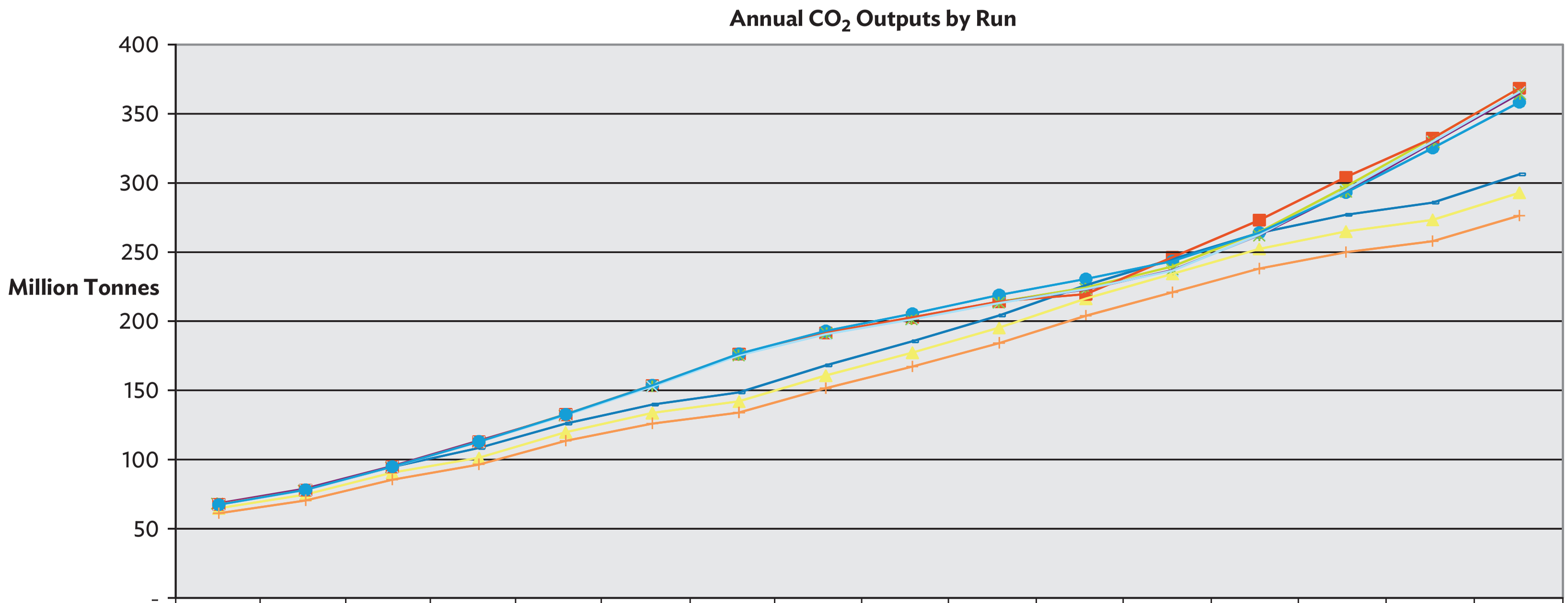


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Run 1	12,324	24,312	12,829	11,188	13,515	11,495	7,875	7,294	6,994	7,773	9,512	9,563	7,667	3,948	912	-
Run 2	5,975	6,622	5,988	3,587	2,257	3,040	5,169	7,459	8,349	9,696	11,537	12,062	10,458	6,394	1,769	-
Run 3	7,328	10,960	9,114	6,626	4,219	2,913	3,328	4,273	5,588	9,502	14,084	15,238	9,448	4,400	1,390	-
Run 4	5,975	6,622	5,988	3,514	2,125	2,919	6,108	8,346	10,000	10,000	10,000	10,000	10,000	6,996	1,769	-
Run 5	5,975	6,622	6,067	3,762	2,257	3,040	5,120	7,371	8,201	9,979	11,911	11,956	10,295	6,291	1,769	-
Run 6	5,956	6,567	6,005	3,592	2,225	3,015	5,056	7,377	8,270	9,514	11,490	12,064	10,427	6,386	1,786	26
Run 7	5,910	6,522	5,948	3,471	1,995	2,389	3,126	4,782	6,622	8,849	10,814	10,159	8,772	5,968	2,767	-
Run 8	8,715	12,163	10,030	7,729	4,981	3,443	3,649	4,353	5,596	9,411	13,473	12,663	10,385	10,368	4,035	-

Plan Year

Source: Ricardo Energy & Environment.

Figure 10: **Summary Results—Annual Carbon Dioxide Emissions**



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Run 1	68	78	95	108	126	140	148	168	185	204	226	245	264	277	286	306
Run 2	68	78	95	113	133	154	176	192	202	214	224	240	264	297	332	368
Run 3	65	75	90	101	120	134	142	161	177	195	216	234	252	265	273	293
Run 4	68	78	95	113	133	154	176	192	203	214	220	246	273	304	332	368
Run 5	67	78	95	113	132	153	175	191	201	213	223	236	263	295	330	366
Run 6	67	78	94	112	132	153	175	191	201	213	224	238	262	295	330	366
Run 7	67	78	95	113	133	154	176	193	205	219	231	244	264	293	325	358
Run 8	61	70	85	96	114	126	134	152	167	184	204	221	238	250	258	276

Plan Year

CO_2 = carbon dioxide.
Source: Ricardo Energy & Environment.

6.3 Learning from the Viet Nam Experience

Principal conclusions were drawn from the investigations:

(i) Applications of CAPRICORN have shown that it is technically feasible to take explicit and simultaneous account of externalities when optimizing integrated generation and transmission system expansion plans for a large and complex power system.

(ii) In all cases, the optimization results were as expected and confirm the robustness of the methodology employed.

(iii) No attempts were made to update most of the data employed when modeling the Vietnamese system previously from 2015 levels. Consequently, the results obtained should not be considered as being indicative of how the Vietnamese power system might optimally be developed in the future.

(iv) Generally, there may be significant potential cost savings from tailoring expansion plans to meet specific targets, i.e., by imposing emission and budget constraints, and by optimizing supply reliability levels rather than applying heuristic installed capacity and available energy margins.

(v) Within linear programming formulations, the relative values assigned to penalties for non-compliance with constraints used to model externalities determine the trade-offs between competing goals; for example, as shown during this study, between levels of supply security and CO_2 emissions.

(vi) With the latest computer capabilities and the availability of increasingly efficient MILP solution algorithms, it is possible to contemplate optimizing not only national power system expansion plans with externalities but also the integrated development of regional systems, such as that constituted by countries making up the GMS.

6.4 Recommendations

There are several principal recommendations based upon investigations:

(i) Power system expansion planning should be undertaken on an integrated basis, with the simultaneous mathematical optimization of generation plant and transmission line commissioning dates and installed capacities.

(ii) Power system expansion planning should be based on the estimated investment costs and construction periods of individual candidate generation and transmission line components, rather than on generic representations.

(iii) Where power systems have a significant existing or potential hydropower component, explicit account should be taken of the degree to which flows, and hence energy availabilities, can vary both seasonally and annually.

(iv) Power system expansion plans should be kept under constant review, given the degree to which their relative optimality may be compromised by significant changes to assumptions made during their derivation.

(v) Organizations responsible for power system development planning should be provided with the resources and personnel necessary to regularly produce and revise integrated expansion plans, with or without external assistance.

(vi) This should increasingly include having access to, and training in, the methodology and application of the most suitable computer software and ensuring that adequate provision is made for its future maintenance and updating.

(vii) While there are several computer programs designed to optimize power system expansion plans, their detailed capabilities, attributes, and levels of user-friendliness should be assessed in detail before decisions are made as to which are the most suitable for future application within the GMS and elsewhere.

(viii) The optimum operation of large storage reservoirs is likely to change as increasing amounts of wind and solar generation are added to hydrothermal power systems. Due consideration should be given as to how multipurpose reservoirs are operated as components of their associated water resource systems, with adequate consideration being given to the effects of both seasonal and annual variations in flow availabilities and water demands.

6.5 Potential Progression Path for Integrated Resource Planning Modeling in the Greater Mekong Subregion Countries

This subsection opens with a brief review of the key aspects in the development of expansion planning software and concludes with recommendations on progression paths for each GMS country.

Development of Expansion Planning Software

The employment of mathematical programming models to optimize the expansion of power supply systems can be traced back to the 1970s, with the use of linear programming formulations to determine the optimum scheduling of generation plant to satisfy forecast electricity demands, as well as providing estimates of long-run marginal costs for use in tariff setting. An example was Program INVEST, developed by Lahmeyer International GmbH, around this time.

Subsequently, the dynamic programming based Wien Automatic System Planning (WASP) program was developed and promoted by the International Atomic Energy Agency, and international lending agencies such as ADB and World Bank have encouraged its application for many years. While successive versions have improved the representation of hydropower plants and other renewable forms of electricity generation, the methodology employed suffers from several important limitations. These include an inability to ensure the optimal introduction of candidate hydropower plants (relying on a selection being made from two pre-ordered lists); or take account of project interdependencies and the need to aggregate electricity demands—often having disparate supply benefits and deficit (unserved energy) penalties. In other words, there is no representation or optimization of associated transmission systems. Like WASP, the Strategist (PROVIEW) program used for PDP in both Thailand and Viet Nam also employs a development plan optimization algorithm and can consider variations in hydropower energy availability.

The single demand area assumption may be acceptable for countries with an extensive mesh transmission system, however, the radial systems associated with hydropower plants remote from principal demand centers mean that the degree to which transmission losses, costs, and capacity constraints may impinge on the (least-cost) dispatch of generation plant can be significant.

Although it is not applicable in the GMS countries in 2020, the development of international power pools further complicates the situation, as decisions increasingly need to be made by individual countries as to whether to import and/or export electricity and, if so, at what tariffs.

Continuous advances in computer capabilities—coupled with improvements in the efficiency of mathematical optimization algorithms—have led to the development of increasingly sophisticated expansion planning programs capable of simultaneously optimizing the scheduling of both generation and transmission components, and hence taking account of multiple demands as well as regional and cross-border interconnections.

It is important to differentiate between programs that can simulate the performance of a given expansion plan and those that optimize such plans. In all cases, some form of load dispatch optimization is necessary to estimate the operating costs that would be incurred in each planning step while establishing levels of supply security and associated penalties for failures to meet forecast demands, e.g., the costs of unserved energy.

Examples of expansion plan optimization software—increasingly based on the application of MILP formulations—include Energy Exemplar's PLEXOS (LT Plan), Power System Research's OptGen, and e-7 Capacity Expansion developed by ABB as a successor to Strategist.

It should be noted, however, that such expansion planning modules often require access to other components of comprehensive modeling suites. For example, the PLEXOS LT Plan is the capacity expansion module of the PLEXOS suite of programs, OptGen is the capacity expansion module of the SDDP suite, while PROVIEW is the capacity expansion module of the Strategist software package. Thus, for example, with OptGen, system operation is simulated using SDDP, while PROVIEW simulates operations using the LFA and GAF modules of Strategist.

Table 9 summarizes this limited selection of expansion planning software.

While the investment costs of connection to a predetermined transmission system node can be included in those of candidate generation plant, with the continuing development of computer capabilities and mathematical programming algorithms, the separation of the generation and transmission aspects of expansion planning no longer seems justified. Examples are where strengthening a transmission system or importing electrical energy may be more cost-effective than providing new generation facilities, and when export possibilities justify the introduction of greater generation capability than required solely to satisfy domestic demands. Similarly, when optimizing the expansion of hydrothermal and renewable generation systems—which applies to those in each of the GMS member countries—adequate account should also be taken of component dependencies, including choices between hydropower project variants, and the effects of constructing upstream storage reservoirs; for example, by evaluating—in a system context—the relative economics associated with a relatively low-cost run-of-river development and those of a more expensive storage project providing higher levels of reliable (firm) energy.

Such considerations prompted the development of CAPRICORN, a program capable of explicitly taking account of these and other factors—such as externalities—when mathematically optimizing power system development plans.

The CAPRICORN model consists of optimization and simulation modules that share a common set of input data files. The optimization module employs MILP to optimize

Table 9: Selected Expansion Planning Software

Software Developer	Suite	Expansion Optimization Module	Simulation Module
ABB	Strategist	PROVIEW	LFA/GAF
ABB	e-7	Portfolio Optimization	PROMOD
Power Systems Research (PSR Inc.)	SDDP	OptGen	SDDP
Energy Exemplar	PLEXOS	PLEXOS LT Plan	PLEXOS LT Plan

Source: Ricardo Energy & Environment.

the commissioning dates of candidate generation plants and transmission lines, as well as import and export quantities, consistent with meeting forecast electricity demands at least net discounted cost.

Since there may always be non-quantifiable factors to be considered when deriving acceptable expansion plans, solutions obtained using formal optimization techniques such as MILP can be viewed as starting solutions that may require subsequent refinement based on detailed electrical network analyses. The CAPRICORN simulation module permits the very rapid evaluation of expansion plans defined by component commissioning and retirement dates. A monthly time-step is employed for deterministic or probabilistic load dispatch optimizations, which can take account of transmission costs and losses as well as supply rationing. Hydropower plant capacity and energy availabilities associated with up to five hydrological conditions can be considered, as well as hydraulic interactions between developments. Generation plant capabilities can also be varied as a function of the expansion planning year.

7 Directions for the Future

7.1 Establishing Policy Frameworks for Integrated Resource Planning with Strategic Environmental Assessment

Traditional Approaches to Power Development Planning

The introduction in chapter 1 provided an indication of how good practice IRP in the current era has evolved appreciably from the practices that were standard 1 or 2 decades ago. In these earlier times, the traditional approach to PDP preparation would have been characterized by the following:

(i) A best estimate base demand forecast would be prepared. In advanced economies, sophisticated end-use forecasting software may have been applied, taking account of energy efficiency developments, DSM programs, and other demand-side initiatives. In less developed countries, econometric forecasting techniques were more prominent— with the inherent shortcoming that the recent past was used to predict the future—with little or no consideration of technological advancements in energy efficiency. High and low forecasts were typically variants of the base case and used principally for sensitivity studies. In these less developed economies, the demand-side was only considered if specific initiatives were well developed.

(ii) Candidate supply options largely focused on projects that had been studied in the past— ideally to feasibility level. Often, these projects had appeared in earlier PDPs. Planners following good practice would consider a diverse range of technologies in their list of candidates. Historically, volatility in oil prices has emphasized the wisdom of maintaining a diverse fuel mix in the power sector, especially in countries such as France, Italy, and Japan, which have few indigenous energy sources. However, since developing countries are often dependent on donor funding for feasibility studies—and since this funding is limited—such studies rarely stretch to a broad range of technologies, thus precluding the widest range of candidates from consideration.

(iii) Optimization modeling is then undertaken for the base set of assumptions, using a software package such as WASP, Strategist, or UPLAN. Sensitivity studies are then undertaken to determine the robustness of the expansion program to the outcome of uncertainties such as fuel prices, capital costs, economic growth, demand, etc. Where appropriate, the PDP optimized from the base assumptions may be modified to take account of the findings from the sensitivity studies and risk analysis.

(iv) The transmission network development plan needs to be integrated into the PDP process. Transmission network expansion is mainly driven by the integration of new generation sources in the power system and—in the case of most of GMS countries where the transmission system is scarce or not very dense—costs of transmission are not negligible compared to investment costs for generation. Several options are possible to successfully integrate transmission aspects in the expansion program. The first option consists of using a software package such as PLEXOS—which enables planners to optimize simultaneously both generation and transmission expansion. But this option has some inconveniences. First, due to its complexity—since only simplified transmission corridors can be modeled—and second, because highly skilled staff are needed to use such complex tools. Even less satisfying from a theoretical point of view, the second option consisting of performing a parallel expansion process for generation and transmission interactively is also a very valuable approach. The key interaction is to include costs of transmission expansion in the cost of candidate supply options used as inputs for generation expansion.

(v) The introduction of cost–benefit analysis in transmission planning is also desirable to ensure a better allocation of financial resources of the countries. None of the countries of the region carry out such studies and the development of their network remains based on standard technical criteria such as the N-1 redundancy rule, voltage, and stability criteria.

(vi) The extent of stakeholder consultation has varied appreciably. In some countries, there has long been a legal requirement to undertake consultation processes for major programs such as PDPs. Nevertheless, in some countries the consultation has been limited to the Cabinet or Parliament. This is becoming increasingly rare, however, due to the increased profile of national and international NGOs such as Greenpeace, Friends of the Earth, International Rivers, and many others. Efforts by governments to push through projects with adverse social and environmental impacts rarely escape the attention of these international NGOs.

Although good practice in PDP preparation has advanced appreciably in recent years, some countries— including some of the GMS countries—follow practices that are closer to the traditional approach outlined above, than to the IRP best practice outlined in chapter 1 and detailed more fully in chapters 2 and 3. There is, however, a general trend in the GMS countries toward good practice in IRP preparation, although in one or two countries the rate of progress is quite slow.

Cambodia, the Lao PDR, and Myanmar do not have the adequate indigenous capability in PDP preparation, and each of these countries has, for many years, been dependent on international consulting firms for the preparation of their PDPs. It is generally the case that the terms of reference for these PDP preparation assignments have changed little over many years and have not kept pace with trends in the industry. In some of these countries, the Japan International Cooperation Agency (JICA) is supporting the development of indigenous capacity in preparing PDPs, as well as in disciplines such as renewable energy and energy efficiency.

TA 9003 is also facilitating a degree of capacity building, through a twinning program. From the gap analysis undertaken under TA 9003, however, it will be some time before these three countries can prepare PDPs using solely indigenous capacity, whereas the PRC, Thailand, and Viet Nam have had enough capacity for many years. Outside TA 9003, the PRC and Thailand have already been providing capacity-building support in aspects of PDP preparation to other GMS countries.

Although Viet Nam has been preparing IRPs with SEAs since 2005, it acknowledges the need for improvements in some areas. One such area is generation optimization software, where the Viet Nam Institute of Energy is using a 12-year-old version of the Strategist package, which most recently has struggled to cope adequately with the size and complexity of the Viet Nam system. Coincidentally, EGAT in Thailand also uses the same Strategist package of a similar vintage and also experiences very slow execution times.

Thailand's EGAT is responsible for preparing the country's PDP. The skill of their staff is impressive—as is the clear integration of related plans for energy efficiency, renewable energy, oil and gas, etc., into the PDP. However, there are some less remarkable aspects of the process, such as the limited collaboration with other agencies having a stake in the power sector.

In summary, the PRC, Thailand, and Viet Nam are ambitious, competitive, and progressive countries, with a strong desire to be leaders in sustainable development. There are clear indications that movement toward good practice in IRP with SEAs will be seen over the next few years. In Cambodia, the Lao PDR, and Myanmar—where capacity in PDP preparation is limited—there are influential advocates for SEAs in the power sector who themselves are directly responsible for environmental protection. The pace of change in these countries is therefore likely to be rather modest, albeit in a progressive direction.

Energy efficiency is a key component in power development planning, often through setting targets in terms of renewable energy capacity or energy production. Energy efficiency plays a prominent role as a proven strategy that nations can apply to reduce consumers' energy consumption, cut emissions, and reduce system power demand. The magnitude of risks associated with energy efficiency programs is often considerably less than those associated with large-scale supply-side projects and programs. Some electricity regulation arrangements may, however, discourage electricity utilities from making investments in energy efficiency, since it decreases their sales and their profits. Under traditional rate-of-return regulation, for example, electricity utility profits are based on the total amount of capital invested in production and distribution, and the amount of electricity sold, and there is limited incentive to invest in energy efficiency measures.

Not all the GMS countries have clearly established targets for energy efficiency, but upcoming policy revisions provide opportunities for countries to benefit from including energy efficiency programs and establishing energy efficiency targets in power planning.

It should be noted that the current PDP approach—developed on a national basis—is an obstacle to the development of cross-border interconnection. Only export lines are readily integrated into this national expansion process. A completely different approach is needed to develop a regional transmission system based on multilateral cooperation.

Consideration of Renewable Energy, Energy Efficiency and Power Trade in Power Development Planning in the GMS

Existing Approaches to the Use of Renewable Energy and Targets

As detailed in the subsection on demand forecasting, the GMS countries need an enabling framework that encompasses policy measures in areas broader than energy policy alone, including economics, taxation, industrial, or labor policies; environmental measures; education and skills development strategies; and instruments to facilitate access to finance or conducive institutional arrangements. Importantly, all these measures need to be well coordinated and working in harmony—like gears in a motor.

Each country—fossil fuel-rich or fuel-importing, large or small, developing or industrialized—is different. There is no single critical success factor that can be applied indiscriminately within any context to guarantee successful renewable energy target setting, and this is valid for the GMS countries. Rather, there are three main categories of factors that must be considered:

(i) **Policy Process**. Policy makers—first and foremost—must take a political decision on renewable energy targets. Underlying this decision are the objectives that policy makers want to achieve with setting renewable energy targets. Targets mainly motivated for the security of supply reasons can best be set in terms of the share of primary energy supply, since—with this objective—renewable energies compete with some fossil energy sources of which the import is considered politically sensitive (e.g., the Lao PDR). But targets for PDP preparation should best be set in terms of electricity. Renewable energy targets set for the greening of industry and innovation purposes can best be set predominantly on a technology-specific basis, to fit with specific industry profiles (e.g., Viet Nam). It should be clear to policy makers that renewable energy target setting and its underlying objectives interact with other objectives. Objectives of ensuring low energy prices or maximizing the rents of domestic fossil energy sources might be affected by ambitious renewable energy targets. Alternatively, a maximization of these objectives might hamper renewable energy implementation. Ideally, policy makers should be well informed of these interactions and decide on priorities to be set regarding potentially conflicting objectives.

(ii) **Contextual factors**. The renewable energy targets to be set are greatly determined by the existing situation in a country, which is dependent on a variety of contextual factors. The main categories of contextual factors that set the scene for policy makers include geographical and physical factors, socioeconomic factors, and energy-related factors. Socioeconomic factors such as demographics, labor, education, and income are mainly responsible for energy demand developments. Finally, energy sector-related factors can be of a varied nature. They comprise the structure of production, infrastructure developments, as well as the legal and regulatory framework set. Together they form the framework against which technical potentials and demand developments should be projected to obtain a complete picture of contextual factors that are relevant for a certain country.

(iii) **Building support for renewable energy targets**. For a successful implementation of renewable energy targets, the support of the main stakeholders around renewable energy is essential. It is therefore a prerequisite to identify which stakeholders are relevant for the renewable energy target setting process and to differentiate these into potential champions and supporters. Structured consultations with these stakeholders can be undertaken, followed by an evaluation of these consultations. Policy makers should then be open minded toward the evaluation findings and be prepared to adapt renewable energy targets or supporting frameworks, if necessary.

Existing Approaches to the Use of Energy Efficiency and Targets

Energy efficiency is widely recognized as the first fuel source in a country's pursuit of energy security, inclusive development, and transition to a low-carbon economy. Investment in energy efficiency could be very attractive since the incremental capital investment is recovered reasonably quickly, energy costs are lowered, and energy productivity is increased, thus helping nations and businesses to be more robust against any sharp hikes in fossil fuel prices.

Significant potential for improving energy efficiency exists in the GMS, but attempts to improve it often fall short because of inadequate national policy frameworks or lack of enforcement of legislation. Among the drawbacks are policies that artificially lower energy prices encouraging wasteful consumption, production and consumption subsidies that distort markets, poorly managed housing stock, and barriers to entry for new market participants.

The general goal in the GMS countries should be to ensure a certain level of production and services with energy consumption optimized for cost. The GMS countries face the added challenge of achieving the target of production and services while confronting energy supply constraints. The deficit in energy supply can very well be met by minimizing wasted energy. Investment in end-use efficiency can help avoid or defer investments in power plants.

Existing Approaches to Considering Cross-Border Trade and Targets

Developing a fully functioning and interconnected transmission network in all countries of the GMS will be crucial for maintaining the security of the energy supply, for increasing regional power trade, and for ensuring that all consumers can purchase energy at affordable prices.

As elaborated in Appendix 1 subsection A1.5.2, reducing the number of synchronous areas by synchronizing them is perhaps the cheapest and easiest way to build such a strong interconnected transmission network within the GMS. However, since technical and operational challenges arise in exceptionally large synchronous areas, interconnecting countries through high voltage direct current (HVDC) systems could be easier from an operational perspective, albeit with higher investment costs. Appendix 1 subsection A1.5.2 recommended that the technical challenges in synchronizing existing independent synchronous areas should be examined and that the GMS should define targets for reducing their number. This might be pursued through multilateral entities such as RPTCC. If a regional coordination center is established—as discussed at the RPTCC in June 2016—or more generally if an association of utilities or transmission system operators (TSOs) are created, this new entity could also oversee carrying out these studies.

As concluded in Appendix 1 subsection A1.5.2, fully functioning and interconnected transmission networks in all countries of the GMS would pave the way for developing and integrating trade and balancing activities in a common regional market, and the RPTCC may be the most suitable vehicle through which to achieve this.

7.2 Characterization of an Integrated Resource Plan with the Strategic Environmental Assessment Approach to Power Development Plan Preparation

Conclusions

Several conclusions on IRP with SEA can be drawn from the previous chapters of this document, and these are worth summarizing.

Internalization of Externalities

A key area of overlap between an IRP and an SEA is that sustainable development is at the root of both. In the rapidly expanding GMS member countries, power sector expansion is already impacting adversely on social and environmental sustainability, and the pace of economic growth is such that the various threats are accelerating in scale and intensity. Major threats are posed by the following:

(i) adverse health impacts due to emissions from thermal power stations;

(ii) loss of livelihoods for people displaced by large generation projects and transmission lines;

(iii) loss of forests and biodiversity due to power projects, especially hydropower reservoirs and transmission lines;

(iv) adverse impacts on fisheries due to reduced flow of nutrients; and

(v) contribution toward global warming and climate change from GHG emissions, particularly from conventional thermal power stations.

To some degree, risks can be mitigated through internal, transactional costs. For example, acidification can be reduced by investment in flue gas desulphurization equipment, and displaced people can be compensated through a well-funded resettlement action plan. External costs, however, are difficult to measure and monetize—i.e., internalize—due to their complexity, the challenges in collecting accurate data, and determining assessment methodologies that align closely with sustainable development objectives. Chapter 5 and Appendix 3 discuss the challenges and approaches adopted in the GMS, and beyond, on each of these counts. The challenges impact on other important aspects of SEAs in IRP.

Stakeholder Consultation

Globally, there has been increasing recognition over the past 2 or 3 decades regarding the merits of consulting with stakeholders on major plans and projects. Although GMS countries have not been in the vanguard with advancing this trend, considerable progress has been made in recent years. Consultation is part of citizen empowerment, which itself is a key element of democracy and good governance. Good governance focuses on governments meeting the needs of all their citizens and not solely select groups in society. Expanding electricity supplies in a country is extremely important if incomes and welfare are to be lifted across society. However, major power projects have detrimental societal and environmental impacts that need to be weighed against the advantages that electricity brings. Minority and low-income groups often have the potential to be disproportionately adversely impacted by hydropower projects in remote areas, with little or no opportunity to share the benefits of thermal projects in urban areas.

Good governance has served to introduce legal frameworks facilitating consultation and enabling NGOs to champion causes such as sustainable development, the rights of minorities, etc. Legal challenges to major generation and transmission projects are not uncommon in some GMS countries—often resulting in significant delays to implementation. As observed in chapter 5, this often results in increased costs, not only for the project in question but also—potentially—future projects. The cause of such problems—often—is the authorities' interpretation of consultation, which can diminish to a top-down, one-way communication of intentions to the public, with two-way consultation largely reserved for interministerial forums.

The recent SEAs in Myanmar and Viet Nam—and many of the IRPs in states of the US—provide examples of good practice in consultation. First, it is essential that the consultation process is truly transparent and participatory, and that all stakeholders are provided with the facts, able to voice their concerns, and receive considered responses to those concerns. Second, the consultation process should be in multiple stages using multiple channels of communication.

In an IRP, for example, public consultation on the draft proposals should be done toward the end of the preparation process and is probably of the highest priority.

The second-highest priority is that consultation on the goals and objectives of the plan should be done at the outset of the preparation process. The third-highest priority is for public consultation on the candidate supply-side and demand-side options that are under consideration. This third stage of consultation provides additional validation of the consultation process.

Earlier chapters remarked on the inertia of engineers and planners, leading them to focus on solutions with which they are most familiar. The list of candidate options may therefore often be repetitive. By consulting at this stage in the process, suggestions can be invited from a wide range of experts in different fields, as well as individuals with perhaps a greater understanding of the critical social and environmental impacts of the options under consideration. States in the US—where there is considerable focus on demand-side solutions and innovative supply-side solutions—often consult at this stage in the process. Managers in the planning agency may be more inclined to heed the suggestion of innovative opportunities from external experts than from their engineers and planners. The harnessing of disruptive technologies in many deregulated economies has largely come from innovative entrepreneurs rather than from the incumbent utilities and agencies.

Resourcing of SEAs and IRPs

Viet Nam PDP SEAs remarked that the expert team did not have enough time nor the budget to consult as widely as they would have liked. The Myanmar Hydropower SEA, however, appears to have learned from these comments and consequently ensured that adequate time and budget were available to their expert team.

Both Myanmar and Viet Nam SEAs, however, were limited in their ability to gather information and to apply methodologies for the quantification and monetization of key externalities. Without adequate budget being allocated for the internalization of externalities—in a quantitative form—IRPs will be unable to include the costs associated with these external impacts when undertaking the optimization of options. Instead, planners will need to depend on the qualitative approach afforded through the SEA, to screen out projects from consideration in sensitive areas.

Assessment of Supply-Side Options

To create equity when assessing conventional thermal generation options and renewable options, all costs and benefits must be taken into consideration. Ideally, all external costs and benefits would be considered but, unfortunately, certain challenges prevent a comprehensive monetization of external impacts:

(i) they are often difficult to quantify and even more difficult to monetize;

(ii) in many cases the scale of the monetized externality does not warrant the effort expended to estimate it; and[102]

[102] The monetizing of GHG emissions is one such debate, since there is considerable difference between—at the lower end—the price of CO_2 based carbon markets, and—at the higher end—the value based on the social cost based on climate change and global warming. Other methods have been tried: (i) direct methods such as contingent valuation and (ii) indirect methods based on combinations of abatement costs and damage costs.

(iii) economists and planners often cannot agree on the most suitable methodologies to apply.

Nevertheless, the range and scale of the potential social and environmental impacts in the GMS countries from not taking account of these externalities are commonly agreed to be unsustainable.

A key advantage of integrating an SEA with an IRP is that the SEA provides a systematic approach that effectively screens out certain options on social and/or environmental grounds—even if all of the adverse impacts of these options cannot be monetized. However, it is still highly desirable to monetize externalities to the extent that this is possible, especially those for options that might potentially be passed over for inclusion in the IRP due to the scale of the monetized externalities.

While it is extremely difficult to settle on a best practice approach to capturing the cost of externalities, TA 9003 strongly recommends that planners should avoid the following:

(i) evading the issue because it is too time-consuming, takes too long, produces values that some parties may consider unduly penalizes conventional thermal generation options, etc; and

(ii) opting for a monetization methodology that yields the lowest possible value, e.g., using market-based carbon pricing for the cost of CO_2 emissions.

The sustainability goals of IRPs with an SEA are unlikely to be attained to a satisfactory degree if the challenges of monetizing externalities are not confronted.

If external costs are to be monetized, the next issue is the approach to screening what may be a long list of supply-side options: large and small, grid-connected or embedded, conventional thermal or based on RES, etc. Subsection 5.2.2 discussed the main approaches adopted by good practice utilities, but the variety in the circumstances in these utilities renders it extremely difficult to say which approach represents best practice. If sufficiently powerful models are available to planners, there are merits in optimizing the demand-side and supply-side options simultaneously. More commonly, however, the demand-side plan is prepared first, and the supply-side plan is optimized after the demand forecast has been modified to take account of the demand-side plan. If the supply-side plan option is adopted, planners must adopt an iterative approach until supply-side and demand-side marginal costs are balanced.[103]

[103] Subsection 4.1.6 highlighted the emerging trend for the screening of renewable energy options, in the last few years, consists of allocating the lowest possible subsidy for an energy or capacity product by a competitive and open bidding procedure. On the supply side, the competition via a transparent procurement mechanism reveals the real cost of projects and ensures least-cost development of the system. As the market evolves, possible subsidies will converge to zero. Iterative tenders allow private sector actors to bid a plant price based on the actual costs.

Assessment of Demand-Side Options

There are several very distinct approaches used to assess demand-side options for inclusion in an IRP. Ideally, a broad range of demand-side options would be identified, their costs and benefits estimated, and the optimization process would include—subject to other objectives and constraints—all options to the point at which the marginal demand-side project equated to the marginal supply-side project. There are issues with this approach. Whilst the marginal costs of supply-side projects can be estimated with a reasonable degree of accuracy—subject to both the usual uncertainties such as the price of fuel and those relating to externalities—estimating the marginal cost of demand-side projects is hampered by considerable uncertainty in terms of the costs to implement a particular initiative and the eventual effectiveness, i.e., the energy saved. States in the US have several advantages to motivate them to use an optimization process. These include decades of documented experience in applying EE&C and DSM and regulated electricity tariffs, ensuring they are pitched at a cost-recovery level.

In the GMS countries, tariffs are often appreciably lower than cost-recovery, which distorts the cost-effectiveness equation in favor of supply-side measures. There can be cultural considerations, too, which explain a reluctance to invest in energy efficiency or why a successful scheme in one country is unsuccessful in another. Viet Nam, for example, has been promoting EE&C for at least 15 years but end users generally remain reluctant to invest.

Many countries—including some of the GMS countries—have adopted an approach centered on a separate EE&C plan. This starts with the country's current energy intensity and a target intensity based on good practice in other countries. Using audits of energy consumption across key sectors and subsectors—and consideration of the potential in each of these—EE&C projects are long-listed, screened, and prioritized to deliver the target energy savings—relative to a BAU scenario—for 10, 15, or 20 years. The BAU demand forecast is then developed using the profile of energy savings relative to BAU.

The key steps in establishing energy efficiency strategies were presented in subsection 5.2.2.

IRP Modeling

All the GMS countries are of a size that necessitates the use of sophisticated simulation and optimization software to prepare a good practice IRP. The software suite used by planners needs to be consistent with the approach adopted for the IRP. Models using MILP appear to have the enhanced power required for optimizing large systems with a sizeable number of supply-side and demand-side options under consideration.

7.3 Realizing the Opportunities

TA 9003 has revealed that before Viet Nam's PDP VII, an SEA does not appear to have been applied to an entire national PDP. Although Viet Nam's Revised PDP VII falls slightly short of a good practice IRP in some respects, the SEA for this PDP amply demonstrated what the IRP with the SEA approach can achieve. Table 2.3 in Appendix 2 shows the difference in the generation mix between the Revised PDP VII and the original version. The SEAs applied to hydropower in countries such as Myanmar, Nepal, and Viet Nam, etc., also demonstrate the potential impact of SEAs on power sector planning.

In countries such as the PRC and Thailand that already adopt proactive policies toward consideration of renewable energy and EE&C, the adoption of IRPs with an SEA would probably yield generation expansion plans with significantly increased non-hydropower renewable energy and EE&C content. In Cambodia, the Lao PDR, and Myanmar—where there has been a degree of reluctance to consider non-hydropower renewable energy—demand-side measures, and importation of power, it is likely that an IRP with an SEA would produce expansion plans that are unrecognizable from their conventional least-cost PDP equivalents. For example, would large hydropower projects in the Cardamom Mountains be included in Cambodia's expansion plan if the social and environmental impacts, such as the loss of biodiversity, were included in an IRP with an SEA?

Cambodia, Myanmar, and—to a lesser extent—the Lao PDR have low connectivity rates, and Myanmar's is one of the lowest in the region. As of 2020, these countries have generally considered technologies based on RES to be best suited to isolated systems. However, grid-scale renewable energy is rapidly becoming cost-competitive with conventional technologies, even without the inclusion of external costs. Micro-grids based on renewable energy and batteries are rapidly becoming cost-effective solutions for remote communities.

International experience suggests that the cost of constructing and maintaining transmission lines to remote communities—added to the relatively high losses associated with long conductors—is often deferring indefinitely the connection of those communities to the grid. Deregulated and liberalized power sectors have facilitated entrepreneurs to harness the various disruptive technologies—especially solar photovoltaics and battery storage—to transform these power sectors at a rapid rate, including:

(i) individual homes, farms, and businesses de-coupling from the grid;

(ii) grid-connected communities de-coupling from the grid; and

(iii) isolated communities establishing mini-grids.

Beyond permitting independent power producers (IPPs), the GMS countries retain—to a great extent—vertically integrated, state-owned power utilities. Viet Nam is taking steps to advance the liberalization of its power sector by establishing a wholesale electricity market (WEM). Although the pace of change is quite gradual, the direction of travel is clearly in the direction of market liberalization. The implication for power planning is that PDPs will become more indicative and discretionary, rather than obligatory. However, with the pace of change in technology, the volatility in markets, etc., countries such as Viet Nam have realized that demand forecasts and PDPs need to be reviewed on an annual basis, which itself suggests that PDPs are becoming inherently more indicative and subject to change at relatively short notice. The transition toward more indicative planning should not weaken the case for IRPs with an SEA, however. If anything, it provides a stronger argument for this approach if social and environmental sustainability is to be safeguarded.

Many developing countries plan their rural electrification separately from that for the national grid. One reason for this is that IFIs provide financial support for rural electrification in highly dependent areas. Best practice, however, is for the PDP to cover both grid and off-grid systems. The traditional model for electrification has been to establish isolated systems based on diesel generation and to then connect these isolated systems gradually to the grid. The high cost of diesel fuel—combined with relatively low-capacity factors—leads to marginal supply costs that are considerably greater than those for grid-connected customers, who typically cross-subsidize their countrymen in isolated systems. The new economics brought about by disruptive technologies is such that the marginal costs are already much closer, and with the gap narrowing at a rapid rate. The challenges for governments, therefore, are to include the planning of off-grid systems in their PDPs and to embrace the opportunities afforded by new technologies and new entrepreneurship.

ADB is supporting regional public goods, within and across the GMS. Arguably, regional public goods form a subset of the externalities that this document has strongly advocated should be quantified and monetized for inclusion in the cost and benefits stream of an IRP. This document acknowledges that a key obstacle to this is the lack of internationally recognized methodologies (i.e., standardized approaches) for quantifying and monetizing many of these externalities. Sharing data on regionally important externalities (e.g., fisheries, flood protection, etc.) would represent a useful step forward and is something that the GMS countries should consider.

7.4 Building the Capacities

General

Each of the GMS countries is at a different stage on the learning curve in terms of their ability to independently prepare a good practice IRP with an SEA. Cambodia and Myanmar are at a relatively early stage in the development of capability for either IRP or SEA. These two countries have historically been highly dependent on international experts—supported by the IFIs—for the preparation of their PDPs, which generally lack most of the elements that distinguish an IRP from a basic, least-cost PDP. The two countries are only starting to recognize the need for SEAs in the power sector, and training is only at a very early stage.

While the Lao PDR also depends on international experts—as well as experts from the Institute of Energy of Vietnam—the Lao PDR has made greater progress relative to Myanmar and Cambodia in adopting SEA legislation and carrying out SEAs in the power sector. As mentioned earlier, in the Lao PDR, the 2012 Environmental Protection Law defined SEAs and stipulated that an SEA shall be conducted while developing policies, strategic plans, and programs (for the energy sector) A Ministerial Decision stipulated further that SEAs were a required part of strategic and sector development plans. SEA Guidelines were subsequently approved in December 2018 to form the basis for the future development of the SEA system in the Lao PDR. Further details of the SEA capacity-building initiatives in the Lao PDR are presented in the following subsection.

In contrast, the PRC, Thailand, and Viet Nam are considerably more advanced in PDP preparation. First, they are almost independent in terms of the ability to prepare PDPs. Second, the PDPs in these countries contain some or almost all the features of an IRP, although each of them has one or more shortcomings that prevent their PDPs from being classified as good practice IRPs. In terms of SEAs for PDPs, the picture is quite varied between the three countries.

In Viet Nam, SEAs have been prepared for the hydropower element of PDP VI and both the original and revised versions of PDP VII. International experts provided considerable support, although the Institute of Energy experts were involved in the process.

The PRC has preliminary EIAs in the power sector which, as mentioned earlier, are the closest equivalent to the SEA concept applied in the other GMS countries, focusing on the analysis of the cumulative environmental impacts of individual power projects within the country's power sector development plan, for example.

Thailand is yet to apply an SEA to power, although voluntary SEA Guidelines have been available in the country for more than 10 years.

Specific SEA Capacity-Building Initiatives in the Lao PDR

The Environmental Management Support Program of ADB was launched in the Lao PDR in October 2010 as a continuation of Sida's two-phased Strengthening Environmental Management program.

One of the key objectives of the program was to ensure that "environmental aspects are merged into national strategic plans and that the role of the Ministry of Natural Resources and Environment (MONRE) in this is recognized by the Ministry of Planning and Investment and other concerned line ministries" (Component 1).

Additional focus was further introduced under this component on building capacity at the Department of Environmental Quality Promotion at MONRE for SEAs and National Environmental Action Plans.[104]

[104] Government of Finland, Ministry of Foreign Affairs. 2015. ***Environmental Management Support Programme in Lao PDR, Phase I: Final Evaluation Report***. Vantaa.

The implementation of this project component led to

(i) successful cross-sector ministry cooperation in developing the SEA ministerial decree and SEA Guidelines, which have been applied in the development of the agricultural, industrial, and tourism potentials in Oudomxay province:
   (a) the SEA Guidelines define the scope and content of an SEA, including key steps in the SEA process; and
   (b) the SEA Guidelines also list 10 economic sectors, including energy, where SEAs are required to accompany the preparation of policies, strategic plans, and programs;

(ii) SEA screening of the Natural Resources and Environment Strategy 2015 and successful cross-sector cooperation with several ministries for setting the MONRE strategic objectives:
   (c) developing and applying the capacity in SEA within the Government of the Lao PDR: MONRE, the Ministry of Planning and Investment, and line ministries;
   (d) 397 participants were reported having received SEA training. These officials were trained to a level, where they have an understanding of the processes and implications, but not all of them to a level where they independently can carry out a strategic environmental assessment. Within MONRE, only three MONRE staff members were considered proficient in full application of SEA methodologies;
   (e) many participants from MONRE, and the provincial departments for natural resources and environment and line ministries got involved in the Golden Triangle SEA and the Oudomxay demonstration project SEAs, and development of SEA guidelines;
   (f) the project also supported two study tours to learn from SEAs in Viet Nam and Thailand, and in parallel with staff training, this project component addressed the needs for process development and approvals in the forms of decrees, instructions, and guidelines.[105]

A new division for SEAs has been established within the Department for Environmental Policy of MONRE with the responsibility to review SEAs for accuracy and to ensure that it is consistent with the prevailing legislation. This responsibility was previously assigned to the Department for Environmental Quality Promotion of MONRE.

[105] TEPCO. https://www.tepco.co.jp/en/corpinfo/consultant/benefit/6-power-e.html.

APPENDIX 1

Gap Analysis Findings on Integrated Resource Planning in the Greater Mekong Subregion Countries

1.1 IRP Policy Instruments, Frameworks and Processes

An important consideration in this subsection is whether jurisdictions should adopt a highly prescriptive approach or something more flexible and responsive to technological and societal changes. Viet Nam has a very prescriptive approach for its power development plans (PDPs), which—with modifications to accommodate a stricter interpretation of integrated resource planning (IRP)—might usefully be adopted by countries such as Cambodia, the Lao People's Democratic Republic (PDR), and Myanmar, that are some years behind Viet Nam in evolving more sustainable power planning. Viet Nam, on the other hand, is pressing ahead with the next stage in market liberalization, with the introduction of a wholesale electricity market (WEM), which may require their PDP to become more indicative than it has been to date. Also, due to the pace of change both internal and external to the power sector, Viet Nam appears to be recognizing a requirement for more frequent updates to its PDPs.

The power planning process in the People's Republic of China (PRC) follows a 5-year planning cycle and is a part of preparing two higher 5-year level plans: (i) a National Plan for Economic and Social Development and (ii) an Energy Industry Development Plan. The national plans provide the framework of key national priorities and targets within which provincial plans are developed. The process is therefore very rigid and prescriptive, as it has been in Viet Nam. There were modifications during 1990–1994, however, when IRP was introduced in the PRC. A distinguishing feature in the PRC, however, is that the planning processes recognize the country's vast size, diversity, and population—requiring devolution of planning responsibilities and coordination between national and provincial authorities.

Policy changes flow from the 5-yearly deliberations of the National Congress of the Communist Party of the PRC, and agencies such as the National Development and Reform Commission (NDRC), National Energy Administration (NEA), and Electricity Power Planning and Engineering Institute (EPPEI) respond to those policy changes. The system is well organized and well coordinated, but unlikely to be highly responsive to changes in the internal and external environment on the power sector during the interval between these 5-yearly meetings of the

National Congress. The PRC was slow in introducing energy efficiency and conservation (EE&C) measures such as demand-side management (DSM), for example.[1]

The United States (US) is also a large, diverse, and populous country that has had a federal system of government since it was founded more than 200 years ago. Responsibility for power planning is devolved to the 50 states, around 34 of which have adopted IRP, and—in more than 21 of these—have laws requiring that IRPs—or Long-Term (Resource) Procurement and Strategic Plans—be prepared. Utilities are required to prepare demand forecasts and action plans for meeting the goals, to provide customers with reliable supplies at reasonable levels of cost, and with manageable risk. These proposals are submitted to the relevant state utility commissions and, after assessment and approval, established as a plan. The plans are re-presented regularly and—in some instances— annually. Some groups of states, and utilities serving several states, also prepare IRPs. Many states require their utilities to include various types of risk analyses within their IRP. Consideration of greenhouse gas (GHG) emissions in IRPs is becoming the norm, and some prepare IRPs that incorporate future carbon dioxide (CO_2) regulations. State public utility commissions can also set energy efficiency and renewable energy goals for utilities. State policies requiring IRPs are credited with increasing investment in renewable energy.

There is considerable variation in the approaches adopted in the various states, and many fall short of good practice IRPs—by international standards—in one respect or another. However, some states, particularly those on the west coast of the US, are extremely proactive—and successful—in promoting renewable energy, energy efficiency, and GHG emissions reduction.

1.2 IRP within an IRP with SEA Framework

Within the Greater Mekong Subregion (GMS) countries, only the PRC and Viet Nam have formal frameworks that approach IRPs with a strategic environmental assessment (SEA) in 2020, and neither country claims to have adopted IRP as a policy. Of the two, Viet Nam is closest to having the requisite frameworks. Viet Nam has legislation requiring a PDP and defines the scope, content, processes, etc., of the PDP in detail. The scope of Viet Nam's PDP has most of the characteristics of an IRP and is already much closer to a good practice IRP than many of those prepared in the US. Also, Viet Nam's PDP framework sits adjacent to an SEA framework and is closely aligned with it; both PDP and SEA frameworks share common goals of economic development and social and environmental sustainability.

[1] D'Sa from the International Energy Initiative notes that many agencies preparing IRPs, including most of those in the US state utilities, work in terms of financial costs to the utility, rather than economic costs. The use of economic costs is more consistent with best practice and is generally required by the guidelines of major development agencies such as the World Bank and the Asian Development Bank.

SEAs are not specific to the power sector and the legal frameworks may require the process to be applied to all significant national plans and strategies with the potential to impact on social and environmental sustainability. As a planning approach, an IRP is not specific to the power sector, either; the core principle to consider supply-side and demand-side measures on an equivalent basis could be applied to other public services such as water supply. Nevertheless, PDP frameworks are unquestionably specific to power planning, and—in addition to aspects such as the responsibilities for preparation, review, and approval, planning horizon and review periodicity, etc., that would remain unchanged—recognizing an IRP approach in the frameworks would require few amendments to PDP frameworks such as those in Viet Nam. Cross-recognition of the SEA frameworks would be useful, including in areas such as guiding where to draw the line between qualitative and quantitative approaches.

1.3 Energy Efficiency

Achieving greater energy efficiency to confront the challenge of sustainable social, environmental, and economic development has been a key component of energy policies worldwide. It is estimated that energy efficiency could make up around half of the reduction needed to drastically reduce GHG emissions by 2050 in scenarios with strong CO_2 constraints.[2] Despite the growing awareness about the merits of energy efficiency and energy efficiency programs and measures initiated in most parts of the world, countries in the GMS are still far from realizing the significant energy efficiency potential due to several institutional, informational, technical, financial, and market barriers that have not yet been effectively tackled. Taking account of the specific socioeconomic context of a country, energy efficiency policies need to be designed and implemented to address those barriers effectively.

In developing an energy efficiency policy, priority should be given to the measures that are expected to drive the desired trends in energy efficiency in each context. The likely outcomes are significantly influenced by key drivers and the barriers, which are often poorly understood. While international best practice provides a benchmark against which comparisons can be made and indications of impact can be derived, the national and regional socioeconomic and political contexts have a significant effect on the successes and failures of policy reform. For example, the increasing use of voluntary schemes in industry in the European context is not necessarily effective in countries where the industry looks to the legislative framework to provide strategic direction, and therefore a transition needs to take place first. To develop this understanding, a monitoring system that will analyze historical progress, inform on current trends—as well as identifying future energy savings potentials—is critical. It ensures that policy makers can focus on priority interventions with the greatest impact and sort the autonomous changes that are occurring globally—such as technology improvements—from the policy measures that are introduced.

[2] European Commission. 2018. *A Clean Planet for All: A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.* Brussels.

Within the GMS there are significant variations in energy consumption patterns and sectors of economic activity. The GMS countries have significant potential for energy efficiency, and this has been addressed in different ways through the development of energy efficiency activities within the last decade. Some countries, like the PRC and Thailand, have taken important steps to encourage the realization of the energy efficiency potential, whereas other countries, such as Cambodia, the Lao PDR, and Myanmar have only started the process recently.

Significant potential for improving energy efficiency exists in the GMS, but attempts to improve it often fall short because of inadequate national policy frameworks or lack of enforcement of relevant legislation. Among the drawbacks are policies that artificially lower energy prices and thus encourage wasteful consumption, production and consumption subsidies that distort markets, poorly managed housing stock, and, barriers to entry for new market participants.

There is a need to develop appropriate normative cost figures for the costs and likely effectiveness of energy efficiency programs and national targets in reducing future demand growth.

1.4 Renewable Energy

Globally, the integration of renewable energy sources (RES) has been a prominent feature of national energy policies for around 20 years. Despite the growing awareness concerning the merits of renewable energy, renewable energy programs and incentivization measures initiated in most parts of the world, the GMS countries are still far from realizing their significant renewable energy potential due to several institutional, informational, technical, financial, and market barriers that have yet to be effectively tackled. While international best practice provides a benchmark against which comparisons can be made, and indications of impact can be derived, the national and regional socioeconomic and political contexts have a significant effect on the successes and failures of policy reform. Within the GMS there are significant variations in energy patterns and economic activity. Significant potential for improving renewable energy exists in the GMS, but attempts to improve it often fall short because of inadequate national policy frameworks or lack of enforcement of legislation.

Most countries in Southeast Asia have set renewable energy targets and have adopted some form of national renewable energy policy to meet them. Of the GMS countries, Thailand and Viet Nam are comparatively more advanced in terms of policy maturity and comprehensiveness.

Thailand is considered the most developed market for renewable energy, and capacities for investment, construction, and operation of renewable energy facilities are growing in the private sector. Thailand was the first country in ASEAN to implement a feed-in-tariff (FIT) for renewable energy. The significant expansion of renewable energy is set out in the 2015 PDP, reflecting targets defined in the Alternative Energy

Development Plan (AEDP), which also dates from 2015. This, in turn, reflects wider national development policies that see renewable energy as an integral part of Thailand's development future. Much of the growth of power generation from RES is coming through private investments, often in smaller generation units. For example, an international solar energy company, Conergy, has built more than 132 MW of solar electricity capacity across several locations in Thailand, with development taking place through local companies and in active collaboration with local government bodies in the investment locations. A recent development in Thailand is the Rooftop Photovoltaics Self Consumption Pilot Scheme, which is part of the transition away from FIT and toward a more mature, market-driven environment. Even without net metering, the levelized cost of energy (LCOE) of a large-scale solar rooftop is only 3% above current commercial prices. The recent Solar Quick Win policy framework includes the proposal to implement a net metering system in Thailand and setting a long-term target installed capacity of 10,000 MW for rooftop solar.

In Viet Nam, the Revised PDP VII considered scenarios with an increased share of renewable energy, including non-hydropower renewable energy, from which the share of coal-fired power plants was reduced. The Renewable Energy Strategy up to 2030 includes several measures that will be developed in detail in the preparation of plans for the implementation of renewable energy activities across the country, including the development of grid-connected renewable energy generation, with private investments selected on a competitive basis.

There are indications that the Government of Viet Nam has developed an effective policy and regulatory framework. In 2018, Viet Nam was the leading country for inbound renewable energy investment in the Asia Pacific, attracting 23 projects. A competitive tendering process can be effectively implemented under the adopted regulations. However, the government has raised some concerns about the risk-sharing mechanism between the private and public partners for awarded independent power producers (IPPs). As of 2020, Viet Nam is under scrutiny because it has developed an effective policy and regulatory framework for new generation projects for IPPs, based on a competitive tender process, but there are several drawbacks, including:

(i) high transaction costs when negotiating a power purchase agreement (PPA);

(ii) a lengthy approval process;

(iii) the absence of suitably long financing tenors;

(iv) lack of skills among sponsors and bankers in assessing risk in such projects; and

(v) ultimately the government is required to provide a sovereign guarantee under the long-term PPA, which may prove expensive.

It is not beyond the bounds of possibility that the government may in the future be tempted to follow a two-pronged policy for procuring generation capacity; for large-scale projects, international competitive bidding seems to have been abandoned in favor of direct awards to international contractors, with the bulk of new large-scale generation projects allocated by ministerial decisions rather than based on a competitive tender process.[3]

Realization of the opportunities that rapid expansion of power generation from RES such as solar and wind will create, is one of the key challenges facing the power sectors in the GMS. Central to this is the development of an effective policy and regulatory framework that reflects an understanding that renewable energy policy needs to go beyond implementing individual policy mechanisms or setting targets. Investors and project developers look at many other issues when deciding whether to invest and so should the governments aiming to promote renewable energy.

As elaborated in the subsection on demand forecasting of the main report, international best practice is to establish enabling frameworks that encompasses policy measures in areas broader than renewable energy policy alone, and broader even than energy policy. These include economic, tax, industrial or labor policies; environmental measures; education and skills development strategies; instruments to facilitate access to finance; or conducive institutional arrangements. Importantly, all these measures need to be harmonized and well coordinated. It is generally the case that the GMS countries have yet to establish these broader enabling frameworks.

1.5 Cross-Border Interconnection and Power Trade

Existing Situation

Even though Viet Nam had been exploring greater interconnection opportunities with the other GMS countries since 2002 or earlier, the current level of such interconnection is extremely limited and is not expected to increase significantly in the coming years. The analysis in the Revised PDP VII confirms this view. The Revised PDP VII does not consider any major development of cross-border interconnection; it only includes some small projects for importing generation from the Lao PDR (the major one was planned to be commissioned in 2016, for 290 MW of import) and the interconnection ratio[4] of Viet Nam will fall from just more than 3% in 2020 to around 1% in 2030. There are also discussions on the possibility of far greater levels of interconnection in the medium term; something reflected in the outcomes of recent Regional Power Trade Coordination Committee (RPTCC) meetings. In consequence, while there are no formal plans or policies for a significant expansion of cross-border connections, such connections are likely to expand in the coming years, which in turn raises the need for a more coherent and coordinated policy framework.

[3] The allocation of projects by ministerial decision is applied regularly in the Lao PDR.

[4] The interconnection ratio is an indicator which determines the interconnection capacity of a country as a percentage of the installed generation capacity (this interconnection capacity is the net transmission capacity available for trading activities for cross-border interconnections after considering all the limitations resulting from operational rules).

A review of the Vietnamese Law of Electricity does not indicate specific barriers for developing cross- border interconnection. On the contrary, the law encourages international cooperation in its article 5.

Article 5. International Cooperation in Electricity Activities

The expansion of international cooperation and international economic integration through electricity activities is based on respect for each country's national independence and sovereignty and mutual benefits. The state encourages and creates favorable conditions for foreign organizations and individuals to participate in electricity activities in Viet Nam; for domestic organizations and individuals to cooperate with foreign organizations and individuals; and for international organizations in electricity activities.

The bottlenecks for developing cross-border interconnections with Viet Nam can be found in fields other than the legal framework. Several severe technical bottlenecks for developing and operating cross-border interconnections can be identified:[5]

(i) There is a lack of an adapted methodology for estimating the economic benefits of a new cross-border interconnection. During the preparation of the Revised PDP VII, the Institute of Energy used only technical criteria for justifying new transmission assets. Cost–benefit analysis needs to be introduced and, in the case of cross–border connections, benefits should be estimated by simulating the operation of both interconnected systems.

(ii) Lack of a common view on operational security beyond the national level does not enable Viet Nam to take advantage of cross-border interconnections for increasing operational security and reducing the cost of system operation in the interconnected system. The case of the interconnection with Cambodia illustrates this lack of a common view and rules. The Cambodian network operation relies exclusively on Viet Nam for frequency control without any internal rules for mitigating the adverse effects on the Viet Nam system. This leads to instability in the cross-border flows, which drastically reduces the possibility to use the interconnection for commercial exchanges.

(iii) There is a lack of precise objectives for integrating the power market and reserve market in the subregion.

These obstacles cannot be overcome on a national basis only. Regional cooperation, based on the development of multilateral associations, is needed for overcoming them efficiently.

Multilateral entities such as RPTCC are probably in a good position to help Viet Nam to build a favorable framework to develop cross-border interconnections. Member

[5] Discussed in more detail in the TA 9003 *Briefing Note on Viet Nam Transmission Issues* from April 2017, appended to the *Inception Report*.

states of such multilateral entities should investigate the way to increase the role of these entities for promoting the development of cross-border interconnections. In consequence, while there is no clear national policy for enhancing cross-border connections, there are also no policies limiting them, and the key to the development of this issue is through active regional cooperation rather than new national policy measures.

Even though the interconnection ratio in some other countries of the GMS is much higher than in Viet Nam (18% in Myanmar and close to 100% in the Lao PDR, against 3% in Viet Nam), the conclusions of the gap analysis for Viet Nam can be extended to all the other GMS countries. Until now, the development of cross-border interconnections in the GMS is mainly driven by large-scale hydropower development for export, with dedicated transmission lines at 230 kilovolts (kV) or 500 kV, and the challenge for GMS countries is still to harness benefits from these major export investments for developing a regional transmission network.

Lack of a Clear Target for Reducing The Number of Synchronous Areas and Developing Regional Cooperation for Trade and Balancing Activities

Developing a fully functioning and interconnected transmission network in all countries of the GMS will be crucial for maintaining the security of the energy supply, for increasing regional power trade and for ensuring that all consumers can purchase energy at affordable prices.

Reducing the number of synchronous areas by synchronizing them is perhaps the cheapest and easiest way to build such a strong interconnected transmission network within the GMS. Nevertheless, new technical and operational challenges arise in exceptionally large synchronous areas. In this case—although potentially more expensive—interconnecting countries through high voltage direct current (HVDC) systems (HVDC links or back to back AC/DC converting stations) could be easier from an operational perspective.

The technical challenges encountered in synchronizing existing independent synchronous areas should be examined, and targets for reducing their number in the GMS should be defined.

Such objectives could be included in the missions of multilateral entities such as RPTCC (and its dedicated working groups). If a regional coordination center is created—as discussed at the RPTCC meeting in June 2016—or more generally if an association of utilities or TSOs is created, this new entity could also be in charge of carrying out these studies.

The development of a fully functioning and interconnected transmission network in all countries of the GMS will pave the way for developing and integrating trade and balancing activities in a common regional market. Multilateral entities such as RPTCC occupy a favorable position for assisting countries in the GMS to take the relevant steps and initiatives to achieve this objective.

1.6 Internalization of Externalities

There is little clarity in the GMS countries on the issue of internalizing externalities. What is clear, however, is that Cambodia, the Lao PDR, and Myanmar do not consider externalities in their PDPs—either as a matter of policy or by a failure to even consider the issue. In the PRC, Thailand, and Viet Nam, there is greater recognition of the need to mitigate the worst environmental and social impacts from the power system, but different approaches are adopted. The PRC and Viet Nam generally place reliance on their SEA—or preliminary environmental impact assessment (EIA) in the case of the PRC—to limit the impacts of pollution on population centers. The PRC, Thailand, and Viet Nam focus on their nationally determined contribution (NDC) commitments for controlling GHG emissions. Generally, the external costs of social and environmental impacts from power projects are not monetized and added to the life cycle costs for use in the optimization process.

APPENDIX 2

Characteristics of Recent Strategic Environmental Assessments

2.1 Viet Nam, Hydropower SEA following PDP VI

Viet Nam's Hydropower SEA was not undertaken contemporaneously with PDP VI, but was undertaken subsequently as a pilot exercise to develop capacity in SEA preparation following the introduction in 2006 of legislation requiring mandatory SEAs for major national plans and programs.[1]

Viet Nam's Ministry of Industry and Trade (MOIT) sought the help of the ADB Environmental Operations Center to develop an SEA following the passing of the Law on Environmental Protection (LEP), 2005. Since then, ADB has provided sustained support to Viet Nam to use SEAs in its PDPs, starting with a pilot assessment on the Hydropower Master Plan in the context of PDP VI.

The pilot SEA study was supervised by a government working group, drawn from members of government agencies most closely involved with SEA and hydropower planning—principally MOIT, Ministry of Natural Resources and Environment (MONRE), Vietnam Electricity (EVN), and the Institute of Energy. The final report and associated documentation were drafted by a core team of Vietnamese experts and international advisors.

The goal of the SEA was to optimize the contribution of sustainable hydropower to national development over the period up to 2025 in Viet Nam. The execution of the SEA followed six phases (as summarized in Figure 6 and detailed in Table 2.1): (i) scoping; (ii) baseline assessment; (iii) scenarios and alternatives; (iv) risk and impact assessment; (v) weighting and trade-offs analysis; and (vi) reporting, including recommendations.

The **Purpose** of the pilot SEA was to enhance the development of sustainable hydropower in Viet Nam through improvements to strategic energy planning so that it reflects more closely the overall development vision and plans of Viet Nam.

---

1 State and Local Energy Efficiency Action Network. 2011. *Using Integrated Resource Planning to Encourage Investment in Cost- Effective Energy Efficiency Measures.* USA.

Table 2.1: **Strategic Environmental Assessment Phases**

Phase	Description
Scoping	Handles what to include in the SEA, the temporal and spatial boundaries, the institutional context and decision scope, and delimitations in terms of issue coverage and stakeholder participation
Baseline Assessment	Provides a baseline to determine the sustainability concerns, challenges, and opportunities in the areas or sectors that are affected by the proposed intervention. It formulates objectives, criteria, and indicators for subsequent components
Scenarios and Alternatives	Generates the decision alternatives for analysis in close deliberation with the decision makers, often through applying a scenario analysis. In some cases, it is possible to introduce sustainability alternatives as part of the package
Risk and Impact Analysis	Deals with the identification and analysis of environmental and social pressures and impacts of the various alternatives
Weighting and Trade-Offs	Makes a transparent and deliberate weighting of impact information through for instance multicriteria analysis or economic valuation.
Recommendations and Reporting	Concerned with drawing out the decision implications from the analysis, including policies, investments, institutional arrangements, and technical mitigation measures, and with the structured presentation of the SEA process and results, in what ways the decision has taken environmental concerns into account, and the motivation for the choices made

Source: Ricardo Energy & Environment.

The **Development Objective** of the pilot SEA was to enable Vietnamese governmental bodies and other stakeholders to undertake and review international state-of-the-art SEA for energy.

The **Immediate Objective** was to perform a pilot SEA of the Vietnamese hydropower plan in the context of PDP VI, with a view to the broader energy sector development. This included informing decision makers and desk officers on significant sustainable development issues arising from the hydropower plan, and reasonable alternatives, and to build capacity and awareness for a full SEA in the next PDP cycle (PDP VII).

With the Viet Nam agencies being relatively new to SEAs, the approach adopted was based on insights into experience and best practice that effective SEAs should

(i) empower government planners and line ministries to drive the SEA as a means for policy integration;

(ii) institutionalize SEAs upstream into more strategic support covering discussions around—for example—the setting of goals and alternatives;

(iii) broaden the scope from environment to assessments of strategically important sustainability aspects; and

(iv) institutionalize SEAs, not as a regulatory burden but more as a learning and decision support process. It should thus make the total planning process simpler, more efficient, and more effective.

The long-term strategic issues that drive hydropower development flow from Viet Nam's Socio-Economic Development Plan (SEDP) 2006–2010, which sets the context for all government programs and plans. In addition to prioritizing the growth and modernization of the economy, the plan emphasizes the need for improved social equity and environmental sustainability. The SEDP stresses economic diversification and modernization, whilst also emphasizing social and institutional reform and wider participation in decision making. The SEDP contains numerous targets relevant to the PDP and the SEA, e.g., the electrification rate; reasonable, effective, and sustainable use of natural and environmental resources in watershed areas; mainstream environmental protection into socioeconomic development plans; expanding forest coverage; and—crucially—integrating climate change into strategic planning and natural resource management.

The PDP and the SEA were also influenced by the Grassroots Democracy Decree 79/ND-CP, which was issued in 2003 to increase community participation in local decision making, especially planning and budgeting. Grassroots Democracy establishes a legal obligation for local decision makers to be consulted in the planning process. The SEA Report noted, however, that, "the capacity of local officials to effectively implement this (Decree 79) varies and is often very limited."

In a similar vein, the government also introduced One Door legal reforms in 2003, intending to improve transparency and accountability in the provinces of Viet Nam. Again, the SEA Report noted that awareness and implementation of these reforms were slow. In 2004, other srategies, decrees, decisions, and guidelines were introduced by the government to devolve certain planning and environmental protection responsibilities to the provinces and to improve transparency and governance. One of these, issued in 2004, was the Orientation for a Sustainable Development Strategy, which is also called Viet Nam's Agenda 21. The SEA Report observed that Agenda 21 effectively redefined the traditional concept of socioeconomic development into "a tight, reasonable and harmonious combination of three elements: economic development, social equity and environmental protection." There was a clear progression from Agenda 21, through to the LEP 2005, SEDP 2006, and ultimately the development and application of an SEA policy.

From 2000 to 2004, Viet Nam was taking timely steps to accord with global initiatives for environmental sustainability, green growth, social responsibility, good governance, etc. Viet Nam was not only taking a leading role in the GMS countries but was establishing itself in the international vanguard on such issues. The rapid progress in laying the policy and legislative groundwork for SEAs, the undertaking of a pilot hydropower SEA, developing human and institutional capacity, though to integrating an SEA with the preparation of PDP VII in 2011—covering a period of just 8 or 9 years—is an example to the other countries in the GMS that are only part-way along this journey.

LEP 2005 requires that an SEA report should cover specific issues:

(i) Briefly outline the plan and/or project objective and/or scope that relates to the environment.

(ii) Outline natural, economic, social, and environmental conditions related to the project or plan.

(iii) Forecast possible negative impacts on the environment.

(iv) Identify data sources and assessment approaches.

(v) Propose environmental protection measures in project implementation.

The team undertaking the hydropower SEA interpreted these as a mandatory minimum requirement rather than the limits of any SEA assessment.

In terms of institutional frameworks for SEAs, LEP 2005 required MONRE to organize an SEA appraisal committee for those strategies requiring approval by the National Assembly, Government, and the Prime Minister.

The provisions of LEP 2005 require renewable energy, including hydropower, to be provided with a range of incentives by the government, the objective being to

(i) increase the ratio of renewable energy in total energy sources,

(ii) contribute to energy security,

(iii) reduce the nation's contribution to climate change, and

(iv) integrate with poverty alleviation.

LEP 2005 also has a requirement that the provinces within a particular river basin shall cooperate to protect the river environment and exploit the water resources to the mutual benefit of their communities.

MONRE issued a circular in 2006 guiding SEA preparation and the detailed structure and content of an SEA. However, the Hydropower SEA Report identified shortcomings in this circular and has recommended to MONRE the need for more effective guidelines and procedures. As with the other agencies in Viet Nam, MONRE was also new to implementing LEP 2005 and climbing a steep learning curve.

Decree 140/2006/ND-CP (22 November 2006) establishes the roles of ministries that are responsible through the SEA planning cycle:

(i) The Ministry of Planning and Investment (MPI) ensures that an SEA is conducted during strategy drafting and considered in strategy appraisal, and monitored against environment protection requirements in strategy and/or plan implementation.

(ii) The Department of Science, Education, Natural Resource and Environment (within MPI) oversees environment protection tasks including SEAs.

(iii) MONRE is responsible for
   (a) organizing SEA report appraisal;
   (b) preparing an annual report on environment protection implementation of strategy and/or plan to submit to the Prime Minister;
   (c) ensuring environment protection consideration in drafting, appraisal, and implementation of strategies and plans approved by provinces and ministries; and
   (d) issuing guidance on environment protection enforcement monitoring and reporting procedures.

(iv) The Department of Appraisal and EIA (within MONRE) is responsible for the SEA issue, including drafting SEA guidelines, proposing the SEA appraisal committee, reviewing and commenting on SEA reports submitted to MONRE.

Viet Nam's laws and policies on issues such as fisheries, water resources, equality of all ethnic groups, etc., also must be taken into consideration in preparing an SEA.

The overall objective of the Hydropower SEA was to assess the potential social and environmental consequences of hydropower development in Viet Nam. Notice was to be taken of the implications of replacing hydropower with alternative sources of generation. In addition to PDP VI, reference was to be made to the National Hydropower Plan, which assessed and ranked the leading candidate hydropower projects across the country.[2] The ranking was based on technical and/or economic ranking; environmental and/or social ranking; and an integrated ranking based on an integrated assessment of the other two rankings, with due consideration of mitigation measures and potential enhancements.

The methodology adopted in the hydropower SEA used trend analysis as the primary analytical tool.[3]

The phasing of the SEA was outlined above and commenced with a scoping exercise that considered what strategic issues should be included in the SEA. The scoping was centered on stakeholder consultations involving key government agencies, nongovernment organizations (NGOs), donors, and others, and the purpose was to

---

2 Government of Vietnam, Electricity of Vietnam (EVN). 2005. *National Hydropower Plan*. Hanoi.
3 Trend analysis is the practice of collecting information and attempting to identify a pattern.

build consensus on the current situation and key issues for consideration in the SEA. The consultations indicated a strong consensus on some issues but divergent opinions on others, thus emphasizing the need to strike balances and trade-offs in some instances. A stakeholder meeting provided good consensus on the following strategic issues:

(i) The importance of hydropower to economic development in the country.

(ii) The effective and sustainable use of water resources is recognized as being of fundamental importance to future hydropower development.

(iii) Recognition of—and compensation for—the impacts of hydropower on project-affected people, particularly those belonging to ethnic minorities.

(iv) The need to maintain the integrity of ecosystems, not only at the site of the hydropower project but also downstream. The cumulative impact of hydropower cascades within a river basin also needs to be recognized.

(v) The hydropower planning process itself requires careful consideration. Respondents held concerns that strategic policy issues are difficult to separate from the hydropower planning process since the nature of positive and negative impacts are conditioned by the planning process. Balancing social, environmental, and economic goals, issues of process transparency, and stakeholder participation were raised as areas of concern, as was the desire to conform to international good practice in these respects.

The next phase in the SEA was to undertake a full environmental baseline assessment. This included: hydrology, water quality, agro-ecology, aquatic and coastal ecosystems, forests, and agriculture. A baseline was also established for the social situation, including sources of income, income distribution and incidence of poverty, the situation of ethnic minorities, and levels of participation in decision making.[4] Incidentally, the SEA study quoted a finding of Hiort and Pham (2004) that public participation in integrated water resource management is still limited in Viet Nam. A baseline of the economic and energy supply situation was undertaken that considered both the supply-side and the demand-side.

An important step in the SEA process is the assessment of risks and impacts—both positive and negative—on people, on the availability of natural resources, and on the integrity of ecological processes. This assessment had two components: (i) the analysis of risks and impacts and including—where possible—an assessment of economic values, and (ii) identifying the potential to mitigate negative risks and increase positive impacts.

When considering scenarios for an SEA, a major challenge in providing information and data for decision support is the interpretation of, and judgment on, the

[4] The SEA study noted the difference between participation and consultation. Participation usually includes decision making by concerned parties while consultation is hearing different actors' views without any commitment to transform these views into decisions.

impact results. The Hydropower SEA Study applied two weighting methodologies to rectify this area of concern, one based on an multicriteria analysis (MCA), and one based on an environmental–economic analysis. In both approaches, however, the dilemma is in choosing whose preferences the scores and weightings should represent since there is considerable scope for a high degree of subjectivity. While analysis and decision making by government agencies should represent the national interest, there is still appreciable scope for divergent interests between agencies. The challenge for the SEA is therefore to reflect a consensus amongst stakeholders, drawing from the lessons learned during the scoping of the SEA.

The economic valuation considered

(i) the cost of supply of electricity,

(ii) the economic cost of air pollutants and greenhouse gases,

(iii) the social and environmental costs of coal mining,

(iv) the social mitigation costs from hydropower,

(v) environmental and natural resource costs of hydropower,

(vi) potential multipurpose benefits from reservoirs, and

(vii) the total valuation of the above and the internalization of these costs and benefits into the overall economic profile of each scenario.

For the base scenario and each of the alternative scenarios, the aggregate economic costs and benefits were determined. The present value of the economic costs and benefits for each scenario were then calculated using the relevant discount rate. The results were then reviewed to highlight any potential shortcomings in aspects of the assessment to this point, before proceeding to the application of scores and weightings in the MCA.

The key messages from the SEA were generally very positive: the pilot justified the introduction of SEA legislation, it supported the level of hydropower proposed in PDP VI, it demonstrated that social and environmental mitigation measures can be costed and internalized into the economic analysis of hydropower projects without compromising their financial or economic viability, and benefit-sharing mechanisms have been piloted and proven to be effective.[5]

Less positive messages included that present approaches to solving social and environmental issues in hydropower development are inadequate and require more effective mitigation and compensation measures to be introduced if hydropower development in Viet Nam is to be more sustainable. Positive impacts

[5] ADB. 2018. *Integrating Strategic Environmental Assessment into Power Development Planning in Viet Nam.* Manila.

from hydropower development are available but these are not yet fully recognized or realized in 2020. Many mitigation measures need to be introduced before development starts, to reduce the risks of negative impacts. For the advantages of SEA to be fully realized, strengthening systems and training are necessary for many parts of the system for planning and implementing hydropower development. Similarly, knowledge and data gaps need to be reduced to ensure more effective integration of social and environmental issues into power planning.

The SEA study recommended changes to the PDP planning process needed to ensure social and environmental impacts are fully integrated into sector planning.

2.2 Viet Nam, SEA for PDP VII

The SEA of the original PDP VII was undertaken just 2 or 3 years after the pilot Hydropower SEA, from which several important lessons had been learned and invaluable capacity building gained.[6] In contrast with the Hydropower SEA, the PDP VII SEA was undertaken in direct conjunction with the preparation of PDP VII. To a large extent, the team of Vietnamese experts and international advisors was the same for the PDP VII SEA as it was for the Hydropower SEA, with MOIT having assigned to the Institute of Energy the task of preparing PDP VII. The SEA for PDP VII was heralded as the first to consider the full range of environmental and social issues, and the first that was prepared under the current SEA Guidelines stipulated in Circular No. 05/2008/TT-BTNMT of 8 December 2008, issued by MONRE. These SEA Guidelines were completed by the MONRE Department of Appraisal and Strategic Environmental Assessment, within the scope of the Sida Strengthening Environmental Management and Land Administration (SEMLA) program.

Between the conclusion of PDP VI and the start of PDP VII preparation, the adverse economic impacts of the 2007–2008 financial crisis were being experienced by Viet Nam and its GMS neighbors, which had a considerable bearing on the electricity demand. With demand growth now forecast to be slower than in PDP—and with the SEA focusing on 12 principal socioeconomic and environmental sustainability issues—it was thermal power generation that bore the brunt of the required reduction in capacity expansion, due to fossil fuel being the greatest source of air pollution and GHG emissions, and because fossil fuel resources are being depleted. Another key output from the SEA was the decision to reduce dependency on coal-fired thermal power generation, for the same reasons.

Aside from the introduction of the MONRE SEA Guidelines, an important change since the completion of the Hydropower SEA was the passing of the Law on Energy Efficiency and Conservation in June 2010—which provided legal guidelines for the electricity development in the future. This law recognized that the electricity sector is less efficient than international norms—due to antiquated equipment and ineffective

6 Government of Vietnam, Ministry of Industry and Trade. 2011. *Strategic Environmental Assessment of The National Plan for Power Development for the Period 2011-2020 with Perspective to 2030 (PDP VII)*. Hanoi.

operating systems—and thus unduly contributing to environmental pollution and climate change. Another change in the policy framework was the introduction of the national program to respond to climate change, approved by Decision No.158/QDTTg in December 2008. This provided guidance on sustainable development, response to climate change as the responsibility of government, society, sectors, regions, etc.

There was also a new SEDP during 2011–2015. The overall goals of SEDP 2011–2015 were similar to those of SEDP 2006–2010, although the targets were modified. If anything, SEDP 2011–2015 placed greater emphasis on the needs of rural and isolated communities. Otherwise, apart from some updating of environmental standards, the legal and regulatory frameworks relating to the PDP and the SEA were broadly the same as for PDP VI and the ensuing Hydropower SEA.

The objectives of the SEA were more specific than those for the Hydropower SEA since the Hydropower SEA was a pilot and included the broader objective of learning lessons on conducting an SEA in power. The SEA for PDP VII had several main objectives:

(i) to ensure that the PDP satisfies the power demand for national socioeconomic development efficiently and sustainably;

(ii) to identify social and environmental issues in PDPs and to analyze and calculate the social and environmental costs of development scenarios in PDP VII;

(iii) to assess key government policies (renewable energy, climate change, environmental flows, EE&C, and benefit-sharing) to reflect the benefits and influence of these policies in PDP VII; and

(iv) to propose mitigation measures to reduce negative impacts or compensate people adversely affected by the implementation of PDP VII.

A two-pronged methodology was adopted for the PDP: assessing social and environmental impacts and identifying options for PDPs. SEA preparation was constrained by the limited time available, and sparse financial and human resources. Data availability proved challenging—an issue that recurred for the Revised PDP VII—and was ameliorated by heavy reliance on judgments and opinions of the experts involved. The SEA focused on how the PDP contributed toward national development to create a balance between economic development, social equity, and environmental sustainability.

After the Hydropower SEA used trend analysis as the primary analytical tool, the MONRE SEA Guidelines recommended this approach, which is like the approach adopted in the European Union. With this approach, analysts look for changes over time in key socioeconomic and environmental issues. Using this approach, the experts focused on issues flagged in the stakeholder workshop and the national consultation.[7]

[7] The national consultation consisted of distributing assessment forms to the relevant provincial authorities and collating and analyzing the returned forms.

Quantitative methods were applied to verifiable indicators such as the loss of forested land area, thus allowing the application of the costs of such impacts to be internalized in the economic analysis. Geographical information systems were used extensively in these methods. For indicators that could not readily be quantified, qualitative assessments were applied, thus allowing the identification of trends over the previous 10 years and extrapolation over the next 20 years.

The phasing of the preparation work for the PDP VII SEA was like that for the Hydropower SEA, but more structured and detailed, with the benefit of the experience of the earlier SEA and subsequent consideration. Table 2.2 presents an overview of the phasing adopted.

The MOIT, Institute of Energy was appointed to lead the PDP and SEA preparation and started by establishing an SEA working group comprising 12 experts from the

Table 2.2: Strategic Environmental Assessment Phasing for Power Development Plan VII

Stage	Description
Scoping	Stage 1 defined the analytical framework for the SEA: (i) Defining the key national socioeconomic and environmental framework. (ii) Assessing the PDP scenarios in PDP VII. (iii) Defining the role of GIS analysis.
Baseline Assessment	Stage 2 included data collection and definition of baseline analysis: (i) Collection of data on each of the identifiable indicators. (ii) Establishing the structure and parameters for GIS analysis. (iii) Studying PDP VII demand scenarios and baseline supply options.
Stakeholder Consultations	Stage 3 covered stakeholder consultations, which were conducted at various stages of the project: (i) The first stakeholder workshop on SEA Scope and Methodology aimed to gather opinions on the selection of environmental issues that were key to developing the analytical framework. (ii) Distribution of Impact Matrices to provincial authorities relevant to PDP VII to gather concerns on potential environmental impacts. (iii) Stakeholder workshop to present the SEA results and receive feedback on assessments and recommendations.
Impact Analysis and Weighting	Stage 4 covered analysis of social and environmental impacts, and the application of weightings: (i) Using economic valuation and scoring mechanisms to analyze the various environmental impacts. (ii) Quantitative analysis of the physical quantities associated with the various social and environmental impacts for the different power supply options. (iii) Economic valuation of the costs and benefits of the social and environmental impacts for the different power supply options. Ranking of projects in each PDP scenario, based on priority indicators, national targets, locational sensitivities, etc.
Mitigation and Compensation	Stage 5 involved the identification of areas and options for mitigation and compensation measures, and assessing the financial implications including potential benefit-sharing mechanisms proposed in Decree 99 of September 2010.
Conclusions and Recommendations	Stage 6 comprised the preparation of the SEA report and submission to the government for appraisal.

GIS = geographical information system, PDP = power development plan, SEA = strategic environmental assessment.

Source: Ricardo Energy & Environment.

various fields. Five members of the group were also members of the PDP VII Working Group. The SEA Working Group was headed by the same Institute of Energy director that was chair of the PDP Working Group.

The SEA for PDP VII provided a mechanism to assess and understand the full range of potential risks associated with different types of power development and transmission, and also a mechanism for identifying and assessing the most effective mitigation and compensation actions where impacts occur. The SEA Report claimed that the SEA for PDP VII adopted "an approach that balances economic development, environmental sustainability, and social equity that has never been done before in the implementation of a master development plan for the electricity sector." TA 9003 has not uncovered evidence to dispute this claim.

A source of subsequent contention was that thermal power—as the source of by far the largest social and environmental impacts—constituted overwhelmingly the largest component of the PDP. It found that by far the greatest potential social and environmental impact was atmospheric pollution from thermal power stations, especially coal.

Under PDP VII, CO_2 and particulate matter releases are estimated to increase more than tenfold during the period up to 2030 and those for sulfur dioxide (SO_2) and nitrogen oxide (NOx) will increase substantially. Moreover, the impacts on human health from atmospheric pollutants associated with thermal power plants are particularly severe in large cities where the ambient air quality is already poor.

As the second-largest source of power generation in Viet Nam, hydropower is not without adverse social and environmental impacts of its own, such as loss of land, loss or degradation of sensitive ecosystems displacement of people and loss of livelihoods, etc. PDP VII indicated additional inundation of more than 25,000 hectares and the displacement of around 61,000 people—more than 90% of whom are from ethnic minorities. The costs and benefits of new hydropower came under scrutiny in the SEA for PDP VII.

PDP VII included nuclear generation, which is attended by low probability but extremely high impact risks, in addition to everyday adverse impacts such as the release of cooling water.

A rather surprising aspect of PDP VII—given the rapid narrowing of the relative economics of renewable energy and conventional thermal technologies—is the low level of renewable energy development proposed in the plan. This is remarkable since renewable energy technologies are more environmentally and socially benign and that the SEA aims to ensure that the modest external costs of renewable energy—relative to conventional technologies—are captured in the economic analysis.

Due to issues such as the avoidance of transmission constraints, the fixed nature of hydropower sites, and the necessity for thermal projects to be distanced from population centers on health grounds, there are inevitable adverse impacts and associated costs—on top of the construction costs—for the substantial transmission line investments in the plan. The potential for renewable energy projects to be embedded close to population centers, and thus reducing the necessity for transmission reinforcement, does not appear to have swung the case for renewable energy to any great extent.

Several recommendations were developed from the SEA:

(i) Greater vigor is required to interconnect the Viet Nam grid with those of Cambodia, the Lao PDR, and the PRC; the PDP is not ambitious in this respect.

(ii) Greater institutional harmonization is required to facilitate the interconnections with neighboring countries.

(iii) Exports of indigenous coal, oil, and gas need to be managed to safeguard future availability for domestic use.

(iv) Application of the Clean Development Mechanism to replace coal with renewable energy.

(v) PDP optimization modeling needs to internalize the external costs of generation technologies.

In addition to the above recommendations, the SEA also made some recommendations for changes to Viet Nam's policies and regulations:

(i) Minimize the number of coal-fired plants and increase renewable energy to meet national targets.

(ii) Studies will be conducted of water resource management in respect of the multipurpose reservoirs, to assess the potential of participatory management of electricity in the new river basin management systems in Viet Nam, and to more thoroughly assess the costs and benefits of the multipurpose projects.

(iii) Training is required at MOIT and the Institute of Energy to ensure adequate capacity to execute an SEA with no external support.

(iv) More rigorous analyses could be undertaken if steps were taken to assess and address data gathering for the SEAs.[8]

(v) The budget for undertaking SEAs needs to be increased if the task is to be performed adequately.

8 TA 9003 has found that this continues to be an area where significant improvements are still possible.

2.3 Viet Nam, SEA for Revised PDP VII

Until Viet Nam's PDP VIII is concluded (expected in 2019), the SEA integrated with Revised PDP VII represents the most recent SEA for the power sector in the country. As noted above, PDP VII was originally published in 2011 but did not receive government approval. A Revised PDP VII was prepared in 2016 to reflect perceived shortcomings in the original version. The first of these is that the demand forecast in the earlier version failed to determine sufficiently accurately the adverse economic impacts of the global financial crisis of 2008. The second issue was the need for the revised PDP—and the associated SEA—to take full account of the various new government policies, strategies, and regulations introduced in the interim.

The optimization analysis in the PDP does not take account of the external costs and benefits associated with environmental and social benefits. The view of the Vietnamese authorities is that the SEA is the means through which these are assessed and—to the extent possible—internalized into the PDP economic analysis.

The SEA report noted that economic growth over the preceding 20 years had been 5%–10%, driven largely by strong industrial expansion. Despite the introduction of laws, policies, and guidelines over this period—focusing on sustainable development—deterioration of environmental quality had been experienced. Industrialization, expansion of power generation, and sustained improvements in personal incomes and living standards could all be identified as having contributed greatly toward environmental degradation.

The challenge of balancing continued economic growth while ensuring social and environmental sustainability is a key purpose of the SEA. Building on the experience from the previous power SEAs in Viet Nam, the SEA for the Revised PDP VII placed an increased focus on mitigation measures to prevent, minimize, or compensate for adverse environmental and social impacts. The SEA also aimed to ensure that the adverse social and environmental impacts arising from thermal power generation were scrutinized and costed more fully. The adverse impacts of hydropower generation were also placed under greater scrutiny, and particularly those associated with resettlement; the aim being that any such resettlement should improve, not worsen, the living standards of displaced people. Overall, the SEA report claimed that it represented the first instance of the full range of social and environmental issues having been integrated into the preparation of a PDP. The report also stated that the SEA is one of the first to be applied to a major sector in Viet Nam.[9]

9 These statements replicate statements in the original SEA for PDP VII in 2011.

The stakeholder consultations held during the initial stages of the SEA preparation provided a consensus on the scope and orientation of the SEA to guide the ensuing implementation:

(i) Calculate and internalize the full range of social and environmental costs and benefits into the Revised PDP VII.

(ii) Ensure that key government policies on issues such as the promotion of renewable energy, climate change, environmental flows, and benefit sharing are reflected in Revised PDP VII.

(iii) Where necessary, identify mitigation and compensation measures to reduce negative impacts or compensate people negatively affected by power development.

As with the earlier SEAs of power, the implementation team was again notably constrained by limited time and resources to collect data from other than existing sources.

Stakeholder consultations were of three principle forms and essentially followed the format used for the SEA for the original PDP VII, 5 years previously: (i) discussions with individual organizations and stakeholders, (ii) workshops with national and provincial stakeholders, and (iii) questionnaires sent to key provincial informants. The consultation objectives and content were also broadly like those set for the previous SEA and covered the key environmental issues and indicators, the SEA approach and evaluation methods, the analysis of the impact assessment results for the different development scenarios, and the feasibility of the draft mitigation measures proposed to rectify the main impacts.

The phasing of the SEA closely followed that applied in the SEA for the original PDP VII, as tabulated in Table 2.2.

The central goal of the PDP—to meet future demand through the most effective and responsible strategy for the expansion of generation capacity—was seen to require a series of trade-offs between the costs and benefits associated with different types of power generation technology. In doing this, the SEA established a set of conclusions and recommendations on the most effective strategy for future power development. The conclusions, when compared with those of the SEA for the original PDP VII, hardened the case against thermal and nuclear power and transmission lines, while emphasizing the positive and negative impacts of large hydropower projects. The other important conclusion was the extremely small and highly localized adverse impacts of renewable energy such as wind, solar, and small hydropower schemes. Recommendations were categorized as general or specific. General recommendations included:

(i) Training is required at MOIT and the Institute of Energy.

(ii) SEA data limitations are a concern, and steps are needed to assess and adjust these data gaps so that future SEAs provide more rigorous analyses.

(iii) While the SEA Guidelines in Circular No. 05/2008/TT-BTNMT of December 2008 provide a strong national framework for SEAs, the SEA report structure specified in the guidelines ought to be reviewed and brought into alignment with international good practice in SEA preparation.

(iv) While important strides were made in the SEA on the internalization of all economic costs into the calculation of the least-cost alternatives for power generation, the full internalization into the base case scenario calculations was not possible. This needs to be developed for future PDPs so that a more rigorous and transparent means to compare the full implications of the different power generation options are available within the core structure of the PDP.

Specific recommendations comprised the following:

(i) The most important recommendation in the SEA was for the reduction of future dependency on coal as a principle means to generate electricity. It was urgently recommended that a strategy be developed that combines improved energy efficiency and accelerated renewable energy development and, in so doing, would partially displace coal-fired generation and attendant adverse environmental impacts.

(ii) Measures to improve management and operational efficiency of power needed to be explored more fully and some examples were presented.

(iii) Recommendations emanating from the earlier SEA for the Hydropower Master Plan were still valid. Essentially, extant planning practices have strengths but were found to not adequately take account of social and environmental factors, e.g., in decisions on the cost and design of hydropower schemes. Other recommendations for hydropower include (i) improvements to the support and compensation for displaced people, (ii) improved measures to ensure an integrated approach to water resources management at multipurpose reservoirs, (iii) development of community forestry and protected area plans for the areas surrounding hydropower sites, and (iv) preparation of biodiversity management plans in localities of high ecological value.

(iv) A series of steps are needed to develop the regulatory framework and operational capacities for the safe development of nuclear power. Also, site selection for nuclear power should not place any nearby sensitive ecosystems at risk from either the cooling waters or the accidental release of radioactive materials.

(v) Actions are needed to limit the impact of transmission lines on forest resources and high-value ecological areas. It was also noted that there is scope for the total number of transmission lines to be reduced by increasing the capacities of transmission lines to 1,000 kV.

Table 2.3 shows the changes between the original PDP VII and the revised plan that included a major reduction in coal fired power generation and a significant increase in

Table 2.3: **Comparison of Generation Mix between Original and Revised Power Development Plan VII**

Generating Mix Component	Generating Capacity in 2030 (MW)	
	Original PDP VII	Revised PDP VII
Coal	77,160	55,252
Natural Gas and Oil	17,465	19,078
Hydropower and Pumped Storage	21,125	21,871
Other RE (including small hydro)	4,829	27,199
Nuclear	10,700	4,600
Imports	6,109	1,508
Total Capacity	137,388	129,508

MW = megawatt, PDP = power development plan, RE = renewable energy.

Source: Ricardo Energy & Environment.

the amount of renewable that will reduce GHG emissions by 100 million metric tons of CO_2 equivalent per year by 2030. In economic value terms, this was estimated to produce a saving of about $1 billion a year, based on the price of $10/metric ton of CO_2 equivalent used in the Revised PDP VII.

Revised PDP VII, approved by Decision No.: 428/QD-TTg on 18 March 2016, demonstrated that integrating SEAs into PDPs can be a positive engine of change. However, this does not happen automatically and, even in Viet Nam, more needs to be done to fully realize the opportunities that are being created. Some areas where important work on integrating SEAs into PDPs was identified as still needing to be done:

(i) Clear guidance on how to implement SEA regulations.

(ii) Support is needed to build capacities to undertake SEAs.

(iii) Increasing the roles of renewable energy and energy efficiency in PDPs will require changes to the process of how these plans are prepared. Planning for many smaller, dispersed generating facilities, which is necessary for renewable energy, will open many opportunities for more flexible and responsive power systems, but this requires different planning approaches.

2.4 Myanmar, Strategic Environmental Assessments of the Hydropower Sector

Myanmar's rivers provide valuable services such as fisheries, irrigation, water supply, flow regulation, and flood risk mitigation. Rivers are also a source of amenity that enhances natural and cultural landscapes that are valued by local inhabitants and by tourists. These value sources explain why—despite the substantial economic benefits delivered by hydropower development—public opposition to large hydropower projects has been growing in recent years. This opposition is—in part— attributable to insufficient transparency in the planning process, and a lack of participatory stakeholder consultation. Opposition and legal challenges to hydropower projects and associated transmission lines have caused a number of these projects to be delayed significantly.

To date, hydropower development has been investor-led, on a project-by-project basis rather than on a basin or sub-basin basis. The Ministry of Electricity and Energy (MOEE) and the Ministry of Natural Resources and Environmental Conservation (MONREC) recognize the need for changes that will ensure sustainable hydropower development in Myanmar, and with an SEA providing a valuable tool for helping deliver on this goal.

The Myanmar Hydropower SEA was prepared with the assistance of the International Finance Corporation (IFC), which has an interest in financing private hydropower developments in Myanmar but strictly based on maintaining sustainable hydropower.[10]

The goal of the SEA was to promote consensus on a sustainable hydropower development pathway for Myanmar. The detailed objectives were to:

(i) define a sustainable hydropower development pathway for at least the next 20 years;

(ii) promote a broad consensus on the pathway in respect of economic, social, and environmental considerations; and

(iii) promote long-term economic development, sustainable utilization, and protection of natural resources and ecosystems.

The SEA aimed to help preserve precious resources in the country, including:

(i) social, cultural, and heritage areas of value;

(ii) areas of biodiversity that are locally, nationally, and internationally recognized as having value; and

(iii) ecosystems that are valuable to livelihoods and the wider economy.

By considering environmental and social values at the river basin level, the SEA aimed to evaluate hydropower sites and areas in terms of their inherent importance and sensitivity. It recommended an approach to achieve sustainable hydropower development also aimed to define safeguard frameworks for the protection and maintenance of sensitive and valuable hydropower areas.

10 IFC. 2018. *Strategic Environmental Assessment of the Myanmar Hydropower Sector*. Washington, DC.

The SEA scope covered all planned hydropower projects with an installed capacity of 10 MW or more. The high-level aims of the SEA included:

(i) to improve the performance and efficiency of policy and planning for hydropower developments by minimizing the adverse impacts on society and the environment;

(ii) to avoid costly mistakes and missed opportunities due to incomplete information on environmental and social impacts and trade-offs concerning hydropower projects;[11]

(iii) to provide a framework for basin-wide assessments, and especially to understand the cumulative impacts of multiple projects in the same basin; and

(iv) to build consensus and public trust through a multistakeholder and participatory process.[12]

Hydropower projects that are delayed at a late stage in their development—due to legal challenges on social and environmental grounds—are not only damaging for the developer, their contractors and financiers, and the government hoping to earn revenues from the project—they also impact negatively on investor confidence in the sector, which may be reflected in higher costs of borrowing and tender prices. An important aim of an SEA is to address such concerns. To this end, therefore, the Myanmar Hydropower SEA considers hydropower projects at the portfolio level to:

(i) reduce or remove the risk of a group of hydropower projects in the same river basin,

(ii) enable cooperation between hydropower developers to identify collaborative solutions for common issues,[13] and

(iii) establish forums through which hydropower developers can cooperate in the best interests of all stakeholders.[14]

An SEA advisory group and six expert groups with different technical specializations were formed to guide the SEA, identify and gather information, review initial findings, and stimulate dedication to the SEA vision. A transparent process was adopted for the SEA, with reporting at each key stage, for review and comment. IFC sought to

---

11 Good information is a key prerequisite for SEAs. In each successive SEA undertaken for the Viet Nam power sector, the SEA Reports highlighted that inadequate information was a source of concern.

12 Many hydropower projects and related transmission lines in Myanmar experience delays due to opposition and legal challenges from environmental NGOs and other stakeholder groups.

13 Hydropower developers in the Nam Theun trans-basin area of the Lao PDR are experiencing delays and disputes due to a lack of coordination on important operational details.

14 The Hydropower Developers' Working Group was launched in 2016 with support from IFC and the Government of Australia. The working group plans to meet quarterly to address important issues in hydropower development, as prioritized by members.

allocate adequate budgets and timescales for consulting with stakeholders and to facilitate data collection and analysis.[15]

A key recommendation from the SEA was to shift the initial planning focus away from individual hydropower projects to basin-wide planning for sustainability.

2.5 The PRC, Preliminary EIA Methodologies

The TA 9003 Gap Analysis found that there is a particularly good understanding at all levels of the PRC government on the need to apply SEA principles to the PDP preparation process. The nearest equivalent to the SEA concept in the PRC considered so far in the GMS countries—Thailand and Viet Nam, in particular—is the concept of plan environment impact assessments (PEIAs), which focus on assessing the cumulative impact of a series of individual projects developed under one program or plan in one particular sector or region. For example, a PEIA may cover comprehensive plans related to the development of a group of power plants, land use, a river basin, as well as coastal development and regional development.

The PRC concept of an SEA includes a higher strategic level of cumulative environmental impact analysis of development programs encompassing, on a larger geographic scale, different sectors across various regions and provinces. The SEAs focus on analyzing policies in various sectors (e.g., agriculture and industry), and the impacts of the plans developed to implement these policies within large geographic regions. In this context, the regional SEAs (i) assess resource and environmental aspects, along with economic and social development trends; (ii) carry out research along established ecological demarcation lines; (iii) simulate possible development scenarios; and (iv) analyze risks to environmental and ecological systems in each region. This approach has not been applied in other GMS countries.

The PRC authorities stress the challenges in applying an SEA nationally and by provinces and regions—in a large, geographically diverse, and highly populous country such as the PRC—and the higher level of strategic analysis required for the considerably more complex cumulative environmental impacts of inter-regional and inter-sector development plans.

The application of PEIAs in the PRC commenced in 2003, following the adoption of the EIA Law that stipulated the elevation of the EIA analysis from individual projects to development plans, and has intensified with the adoption of the 2009 PEIA ordinance, which facilitates the actual implementation of the EIA Law. Also, the application of the PEIAs, including PEIAs for PDPs, has been facilitated by the strategic change of the country's development priorities in 2012 from a high rate of economic development growth to a quality green growth, with much greater

15 The SEAs for the PDPs in Viet Nam highlighted that they were severely constrained by an insufficient budget and an inadequately short timescale. IFC appears to have learned from these findings.

consideration for protecting the environment. This new development strategy is being implemented through the preparation of plans for national, energy, and power development, with appropriate coordination of key development targets on all levels of planning and government. The inclusion of PEIAs in the corresponding economic development plans is mandatory. Recent amendments to the environmental legislation increase personal accountability of officials for achieving environmental results and increase penalties for non-compliance, which further enables the application of PEIAs, including PEIAs in the PDP process.

There is, however, a good understanding of potential areas for improvement with the PEIAs in terms of improving (i) capacity and methodologies for assessing impacts in certain sectors and industries, (ii) the coordination between planning and environmental authorities, and (iii) streamlining the categorization of relevant guidelines.

The 2003 EIA Law stressed that an SEA is complementary to the EIA process covering PEIA. While PEIAs are a mandatory component of development plans, the SEAs have only advisory character. The PEIA recommendations are mandatory for implementation, while the SEAs are also more of an academic research type of activity with no direct impact on decision making.

The SEAs have not been specifically defined in environmental laws. Nevertheless, the EIA Law and the Environmental Protection Law are considered to provide the basis for SEAs by elevating the need for EIAs from an individual project to sector and regional plans and mandating the inclusion of environmental protection plans in the development plans.

SEAs have been referenced alongside EIAs as a means for impact assessment of development plans in the 13th Five-Year Plan for Protection of the Ecology and Environment (2016–2020). SEAs are also considered to apply to analysis of policies and related plans, designed to facilitate policy implementation.

The priorities of the Five-Year National Development Plans, along with the research carried out by scientific institutes, provide the main guidance about defining the SEA's scope and focus by the Ministry of Ecology and Environment.

From 2007 to 2010, the then Ministry of Environmental Protection of China carried out an SEA pilot for five mega-regions with a territory of 1.1 million square kilometers and a population of 300 million. The resulting SEA of the key industrial developments in these five regions has become an important reference for national and major regional strategies, an essential supporting experience for developing major planning and local policies, and the key basis for organizing industries such as thermal power, chemistry, petrochemistry, steel, etc. After concluding the SEA for the five mega-regions, the then Ministry of Environmental Protection organized and completed an SEA for the planning of the development of (i) key areas of the PRC Western Regions and its industries in 2011–2012, and (ii) the Central Region of the PRC in 2013–2014.

2.6 SEA of Hydropower on the Mekong Mainstream

The Mekong River Commission (MRC) is an "...inter-governmental organisation that works directly with the governments of Cambodia, the Lao PDR, Thailand, and Viet Nam to jointly manage the shared water resources and the sustainable development of the Mekong River."[16] The mission of MRC is "to promote and coordinate sustainable management and development of water and related resources for the countries' mutual benefit and the people's well-being."[17]

With the background that 12 hydropower schemes were proposed on the Mekong mainstream, amid fears that any one of these "could have profound and wide-ranging socio-economic and environmental impacts in all four riparian countries" in the Lower Mekong Basin (LMB), and since "the 1995 Mekong Agreement requires that such projects are discussed extensively among all four countries prior to any decision being taken," MRC engaged the International Centre for Environmental Management (ICEM) to undertake an "SEA of the proposed mainstream dams to provide a broader understanding of the opportunities and risks of such development."[18] The ICEM team comprised 10 international specialists, together with 13 specialists from Cambodia, the Lao PDR, Thailand, and Viet Nam.

Generally, the 12 LMB projects had previously only been studied on a project-by-project basis by their respective national authorities (e.g., by undertaking EIAs), without an overall spatial or integrated development plan for the river.

The Procedure for Notification, Prior Consultation, and Agreement (PNPCA)—a protocol under the 1995 Mekong Agreement—was triggered for the first time in September 2010 with the official notification from the Lao PDR of the proposed Xayaburi mainstream project. The MRC SEA was therefore intended as an input to the PNPCA process, and into the MRC Basin Development Plan, and thereafter to support national planning decisions.

The SEA assessed the 12 projects in five separate groupings, spanning three distinct hydro-ecological zones. There were four phases to the SEA:

(i) **Scoping**. Defining key issues of strategic concern.

(ii) **Baseline assessment**. Past trends in the strategic issues, and projection to 2030 without mainstream hydropower projects.

---

[16] Mekong River Commission. *About MRC*. http://www.mrcmekong.org/about-mrc/.

[17] Footnote 16, Section 2.6.

[18] International Centre for Environmental Management (ICEM). 2010. *Strategic Environmental Assessment of Hydropower on the Mekong Mainstream: Summary of the Final Report*. Mekong River Commission.

(iii) **Impact assessment**. Effects of mainstream hydropower on the trends.

(iv) **Risk avoidance and mitigation**. Identifying ways to avoid and/or mitigate risks and enhance benefits.

Intensive consultation was undertaken, with more than 60 line agencies, 40 NGOs and civil society organizations, and 20 international development organizations. The PRC participated through the Ecosystem Study Commission for International Rivers. Views and opinions expressed during the various meetings and workshops guided and shaped the various phases of the SEA. MRC noted, however, that the scope of the SEA was such that some important issues raised by stakeholders could not be addressed due to the divergence of opinions on future energy demands—nationally and regionally.

Considering the potential contribution from the 12 LMB projects toward continued rapid growth in regional demand for electricity, the SEA identified three trends in favor of expanding hydropower's contribution: (i) increased regional cooperation, (ii) commitment to diversify fuel sources and reduce dependency on fossil fuels, and (iii) international trend to reduce GHG emissions from power.

The power benefits of mainstream hydropower are largely concentrated in the Lao PDR (>70%), with Cambodia and Thailand (11%–12%) and Viet Nam (5%) also sharing the benefits.[19] The mainstream hydropower projects would also positively impact climate change mitigation in the region, by reducing GHG emissions.

The mainstream hydropower projects would have significant net negative impacts on fisheries and agriculture, and these impacts can be only partially mitigated. Agriculturally productive land would be inundated, and reduced sediment transport would adversely affect soil fertility. Incomes and nutritional health would be adversely impacted.

The SEA found that the benefits of hydropower would accrue to grid-connected electricity consumers and developers, financiers, and host governments. In contrast, most costs would be endured by poor and vulnerable riparian communities and some economic sectors. Benefits are also unevenly shared between countries, with Cambodia and Viet Nam suffering net short- to medium-term losses due to the combined effects on fisheries and agriculture outweighing power benefits.

Mainstream hydropower projects would add to the basin-wide eco-morphologically adverse processes that are already being experienced due to hydropower projects in the Mekong tributaries. Wetlands are likely to endure serious and irreversible environmental damage, adverse impacts on long-term health and productivity of natural systems, and losses in biological diversity and ecological integrity.

[19] Projects will typically be developed by the private sector, and therefore the benefits will be shared between the national governments, the developers, and the financiers.

The MRC SEA considered and consulted on four strategic options of importance to the LMB countries:

(i) no mainstream dams,

(ii) deferred decision on all mainstream dams for a set period,

(iii) gradual development of mainstream power, and

(iv) market-driven development of the proposed mainstream projects.

These four options were assessed in detail, based on the SEA findings. Applying a decision tree process, detailed recommendations for each strategic option were made, to provide the LMB governments with guidance on critical issues, whichever strategy is adopted. The SEA noted that, when it was initiated, stakeholders held strongly divergent views on mainstream hydropower development, with line agencies and NGOs generally steadfast to their sector mandates. However, the SEA observed considerable common ground between stakeholder individuals, as follows:

(i) concern about the potential impacts of mainstream hydropower;

(ii) the requirement for convincing evidence of the need for these projects; and

(iii) concern that inadequate consultation and discussion had been undertaken across those governments with affected communities.

The SEA reported that a "significant number of SEA stakeholders felt that political decision makers should give due consideration to the strategic option of deferring a decision on mainstream development until key uncertainties are reduced, alternatives had been fully considered and measures to manage development risks were agreed upon through a combination of MRC-led and bilateral processes."

Due to the significance of the risks and the various uncertainties—many of these due to knowledge gaps—in addition to the concerns on consultation deficits, the SEA team recommended the adoption of Strategic Option #2, i.e., deferment of mainstream development. Specifically, "decisions on mainstream dams should be deferred for a period of 10 years, with reviews every 3 years to ensure that essential deferment-period activities are being conducted effectively." A further key recommendation was that "the Mekong mainstream should never be used as a test case for proving and improving full dam hydropower technologies."

TA 9003 gap analysis in the GMS countries has found that the reaction to the MRC SEA broadly mirrored the divergent views on mainstream development that presaged that study; some individuals expressing strong concerns on the potential negative impacts of such development, with others strongly opposed to the development moratorium recommended by the SEA.

APPENDIX 3

Current Practice in the Greater Mekong Subregion Countries

3.1 Overview

The PRC, Thailand, and Viet Nam have the capacity and legislation to carry out key elements of the IRP with SEA approach in preparation of PDPs in terms of (i) demand forecasting, (ii) analysis of energy efficiency and renewable energy options, (iii) internalization of externalities, and (iv) PDP optimization.

Cambodia, the Lao PDR, and Myanmar are at an initial stage of developing capacity and legislation in the above areas and are assisted in varying degrees by international consultants in the preparation of their PDPs.

3.2 The PRC

Demand Forecasting

The preparation of the PDPs falls under the jurisdiction of the National Development and Reform Commission (NDRC)—the national planning agency—and the National Energy Administration (NEA), which oversees formulating and implementing power plans and policies. The actual preparation of the PDP has been assigned to the NEA think tank—the Electricity Power Planning and Engineering Institute (EPPEI)—which has subdivisions throughout the provinces and partners with research institutes.

EPPEI has considered three demand scenarios in preparing the 13th Five-Year Energy and Power Development Plan, including energy efficiency impacts. The scenarios have been based on considerations of gross domestic product (GDP) and population growth, along with higher and lower levels of the target of reducing the energy consumption per unit of GDP by 15% by 2020 relative to the 2015 level. Additional considerations have been given to expected norms of efficient coal consumption for generating a unit of power, emissions reduction targets, and the impact of new technologies.

Analysis of Energy Efficiency Options

The national energy efficiency targets are subdivided and assigned with clear accountabilities for delivery to provincial governments and administrators of key national programs. Provincial targets set by the State Council through the relevant ministries and agencies, having the status of departments of the State Council.

The key energy efficiency targets are expressed through indicators for (i) total energy consumption and (ii) coal consumptions. The targets are set based on submissions from the provincial governments that include consideration of factors such as the development level, industrial structure, energy intensity, total energy consumption, per capita energy consumption, and the level of energy self-supply in the province. Energy efficiency targets for lower levels of government at the prefectural and county levels are supervised by provincial governments. Targets for individual enterprises, which are large energy users, are set by the central government under energy savings responsibility contracts. Lower levels of government set energy efficiency targets for smaller users. Large projects are required to undergo energy audits.

Energy efficiency targets are reviewed on an annual basis. The central government (NDRC) sends evaluators in multidisciplinary teams from relevant ministries and agencies to provinces to assess progress in energy conservation against key indicators. About 40% of these key indicators focus on progress in reducing energy consumption and 60% on related activities (e.g., square meters of retrofitted buildings).

The energy efficiency targets are an important component of the Five-Year Plan for Energy Savings and Emissions Reduction (2016–2020), issued by the State Council in early 2017 to achieve the goal of reducing energy consumption by 15% in 2020 compared with 2015. The plan focuses on promoting energy saving in key sectors, including manufacturing, construction, transport, trade, agriculture, and public institutions.

Energy efficiency considerations are included in the electricity demand forecast nationally, prepared by EPPEI.

Analysis of Renewable Energy Options

The Renewable Energy Law of 2005—amended in 2009—sets the general principles of promoting renewable energy in the PRC. The Renewable Energy Plan is part of the Power and Energy Sector Development Plan and is prepared and approved through the same processes which apply to the power and energy plans.

The renewable energy plan includes the following elements, as defined by the renewable energy law:

(i) development targets,

(ii) major tasks,

(iii) regional layout,

(iv) key projects,

(v) progress (milestones),

(vi) construction of associated power network,

(vii) service systems, and

(viii) safeguards.

Internalization of Externalities

In the PRC, consideration of social and environmental costs is largely limited to the EIA stage of project development, rather than at the high-level planning stage of an IRP, and PRC has guidelines for the preparation and reviewing of EIAs. These EIAs focus on assessing costs and benefits related to emissions and solid wastes—primarily from coal—and their abatement, along with any other cost and benefits that might be quantified in a specific project or program. TA 9003 understands that the PRC is looking to capture the external costs of GHG emissions using market values from the embryonic national emissions trading system.

PDP Optimization

EPPEI, the planning institute in the PRC, uses a planning software package developed by the Central Technology Institute of China. The program focuses on multi-energy integration. The development of the PDP is based on a sequenced consideration of (i) demand forecast, (ii) required generation mix, (iii) power grid availability, and (iv) required grid extensions.

3.3 Thailand

Demand Forecasting

In Thailand, the power demand forecast of the 2015 PDP was integrated with the Energy Efficiency Development Plan (EEDP) and the Alternative Energy Development Plan (AEDP). The forecast applied end-use and econometric models, in combination with GDP growth projections from the National Economic and Social Development Board. The difference in peak demand by 2036 between a business as usual scenario and a base case scenario in which the EEDP and AEDP measures are integrated was 9,645 MW—or 16.3%.

Thailand's optimization modeling for the PDP did not consider EE&C initiatives as candidate options. Instead, the demand forecast was modified using the EEDP.

Analysis of Energy Efficiency Options

As part of the PDP preparation in Thailand, the EEDP—as well as AEDP—is integrated into the process. Short- and long-term energy conservation targets are established, consistent with Thailand's NDC commitments, and with separate targets for the four main economic sectors. After establishing the targets, the EEDP approach proceeded as follows:

(i) Potential EE&C measures to achieve the target were identified, by largely drawing from those proven to have been successful in other countries.

(ii) Consultation on the potential measures was undertaken with business, the public, academia, and government.

(iii) Audits of final energy consumption in the main economic sectors and subsectors were undertaken.

(iv) The EE&C technical potential in each sector and subsector was estimated.[1]

(v) Following intensive consultations with end users and other stakeholders, strategies were developed to structure the EEDP, including the preparation of action plans and budgets.

(vi) The expected benefits to 2030 were determined in monetary terms. These benefits included direct benefits—principally in terms of energy expenditure savings—and indirect benefits—such environmental quality improvements and the positive macroeconomic impacts due to reduced fuel imports, for example.

The EEDP does not provide any indication that individual EE&C measures would be cost-effective. However, one of the critical success factors in the plan is the acknowledgment that energy prices should reflect actual costs and that tax measures are required as a tool to promote energy conservation and to reduce GHG emissions.

Analysis of Renewable Energy Options

In Thailand, the AEDP aimed to encourage waste-to-energy, biomass, and biogas power generation as the priority. The AEDP estimated the potential capacity from each RES and remarked that technology improvements are likely to improve the competitiveness of renewable energy relative to conventional sources, especially liquefied natural gas (LNG).[2] The AEDP target was to increase renewable energy from 8%–20% over the planning horizon of the plan, reaching an installed capacity of 19,634 MW by 2036. An important element in the AEDP was the consideration of spatial characteristics relating to generation from crop residues, the renewables purchase scheme, and the impacts on the transmission and distribution networks.

1 Unfortunately, it is not clear whether economic analysis was applied to determine which measures were cost-effective and, if so, to what degree.

2 In 2015, solar and wind energy were judged to not be competitive with generation using liquid natural gas.

On the issue of economic analysis for renewable energy projects, the methodology adopted in the AEDP was, briefly, as follows:

(i) Assess the RES resource potential for each renewable energy technology, on a geographical basis, together with current rates of RES resource consumption.

(ii) Consider the demand projections on a spatial basis, i.e., demand at principle substations.

(iii) Consider the capacity of transmission lines to carry electricity from renewable energy projects.

(iv) Establish the merit order of the various renewable energy technologies based on the levelized cost of electricity, taking account of the social and environmental benefits of renewable energy—including GHG emissions reduction and employment creation, in addition to the capital costs, fuel, and operation and maintenance costs over a project's life cycle.

(v) The renewable energy generation capacity targets were then established for each geographical area and each renewable energy technology using the renewable energy supply–demand matching principle, i.e., the available renewable energy resource potentials were sequenced in merit order based on demand and transmission constraints in the area.

Aside from the approach outlined above, the AEDP set a 20% target for net electrical energy demand in 2036 being met by renewable energy to conform with fuel diversification targets.[3]

Internalization of Externalities

In Thailand, the Electricity Generating Authority of Thailand (EGAT) approach to internalizing externalities for the optimization studies did not include monetizing CO_2 emissions using either a social cost of carbon or a market-based price of carbon, although EGAT concedes that this is possible using their Strategist software package. However, EGAT considers that incorporating other externalities such as pollution, land use, deforestation, etc., into the PDP modeling, may be a challenge for expansion planning software suites. The approach by EGAT was to cap the tonnage of CO_2 emissions each year, following Thailand's NDC commitments.

PDP Optimization

Thailand uses an old version of the Strategist planning software package to optimize its PDPs and although this package is slow and underpowered for contemporary requirements, the planners in Thailand are skilled in finding work-arounds that, in part, redress the shortcomings of this package.

[3] The share of renewable energy at the end of 2014 was 9.9%.

3.4 Viet Nam

Demand Forecasting

The analysis in the Revised PDP VII (RPDP VII) was based on three scenarios that reflected the outcomes of the SEA in the original PDP VII. The first scenario (PA1) was a base case that projected economic growth at 7% per year throughout the plan period 2015–2030, and the growth of demand for power to be much lower than in the original PDP VII.

The figures in PA1 include assumptions of slower socioeconomic growth and significant energy savings due to a sustained national program on energy efficiency. These figures better reflect the national development priorities, e.g., a substantial increase in renewable energy and a major decrease in GHG emissions from the original PDP VII base case.

The second scenario (PA2) used the same patterns of growth of demand as PA1, including energy efficiency savings, but increased the proportion of renewable energy (other than large hydropower) to 6.5% of the total generating capacity. Under PA2, the total generating capacity in 2030 was higher than the base case to reflect the variable nature of some renewable energy sources and ensure the supply of electricity. The levels of renewable energy in this scenario were the highest feasible at the time of the analysis during the revision of PDP VII. However, developments in solar, wind and other renewable energy technologies indicate that renewable energy can have a bigger share in power generation. Future PDPs should anticipate and reflect the lower costs and technical improvements in producing renewable energy.

The third scenario (PA3) was a high load scenario. It was prepared to test the implications of a situation where energy efficiency savings were not achieved, and levels of demand were higher than in the base case of RPDP VII. This scenario does not replicate the original PDP VII as it still aims to reduce coal generation and increase the use of renewables in a situation where generation capacity needs are higher than predicted. PA3 can be considered a sensitivity analysis and is seen to be the least likely of the three scenarios to transpire.

Analysis of Energy Efficiency Options

In Viet Nam, improvements in EE&C form a key element of the strategy for the power sector. Various assessments indicated that improvements were possible:

(i) The Electricity of Viet Nam (EVN) DSM Assessment Study shows that a savings potential of around 36% could be achieved in the residential sector, and more than 20% and 12% could be attained in the industrial and commercial sectors, respectively.

(ii) The World Bank's Commercial Energy Efficiency Program, which involves pilot projects in commercial and industrial sectors, indicated that 15%–30% in project savings was possible.

(iii) A study supported by the Government of Denmark established that compliance with current minimum efficiency standards in the construction sector could lead to a savings of 30% or more, compared with the prevailing construction practice.

The application of the various EE&C measures, and related targets, have the potential to bring down the country's elasticity of electricity demand relative to GDP growth from a high of 1.90 in 2010 to 0.85 in 2030, which is consistent with such elasticity rates of many energy-efficient developing and industrialized countries.

The Revised PDP VII base case included a scenario with increasing energy efficiency, which was consistent with

(i) the strategy set out in the Viet Nam Energy Efficiency Program (VEEP) for the period 2010– 2015, and

(ii) an MOIT program developed in 2009, with 5%–8% electricity savings initially and gradually increasing this to 20% of the total electricity demand during the period 2015–2030.

Under this scenario, electricity generation savings increase from 1,639 GWh in 2015 to more than 22,000 GWh by 2030. The reduction of electricity demand would—potentially—greatly reduce dependency on coal-fired power generation, and 16 coal-fired power plants identified in the baseline scenario would no longer be needed during the PDP period (2015–2030).

Elaborate economic analysis to establish the case for additional EE&C measures does not appear to be warranted in Viet Nam, based on the energy intensity statistics, particularly those in the industrial sector, in comparison with other countries. The situation was widely considered to be unsustainable and the solution lay in more effective EE&C.

Analysis of Renewable Energy Options

As part of MOIT Viet Nam Energy Outlook, 2017, supported by the Danish Energy Agency, an analysis was undertaken using the Balmorel power system planning model, which allows assessment of renewable energy integration into Viet Nam's power system, including variable RES such as wind and solar. Modeling data was generally taken from the Revised PDP VII. A range of development scenarios was explored, including several CO_2 price levels, and also including an unrestricted scenario that—hypothetically—assumed no environmental or renewable energy policies are pursued. As a base case, a CO_2 price of $7/metric ton was assumed in 2020, and $20/t thereafter. The $7/t value corresponded to the estimated monetary benefits that producers could earn from emissions reduction credits, i.e., a market-based value. The $20/t value represents an estimate of CO_2 externality costs. As remarked elsewhere in this document, these values are appreciably lower than figures based on the social cost of carbon, and therefore do not penalize fossil-based generation as much as the application of the social cost of carbon would. However, the Balmorel studies also include a CO_2 price high scenario where $35/t was added to the CO_2 shadow price. In this price high scenario, the CO_2 price rises from $20/t in 2020, to $40/t in 2030, and $45/t from 2035 onward. These values are more representative of the social cost of carbon estimates.

In January 2019, the Viet Nam Prime Minister issued Decision 02 to amend certain articles of Decision 11 on mechanisms for encouraging the development of solar power in Viet Nam. Decision 02 promulgates a new payment scheme to replace the net metering structure of the rooftop solar power projects under Decision 11. Decision 02 did not provide any model PPA for rooftop solar power projects and it only applies to limited rooftop solar power projects which have commercial operation dates, together with electricity meter readings confirmation, prior to 1 July 2019. In March 2019, the MOIT issued Circular 05/2019/TT-BCT (Circular 05) to replace the old-model PPA for rooftop solar power projects attached to Circular 16, and to extend the FITs for all rooftop solar power projects. Circular 05 was to become effective on 25 April 2019.

Key highlights of Circular 05 include the following:

(i) **FiTs for all rooftop solar power projects**. Prior to 1 January 2018, the FIT for rooftop solar power projects was approximately $9.35/kWh, exclusive of VAT. This FIT is designated to apply to outstanding rooftop solar power projects that came into operation prior to 1 January 2018. From 1 January 2018 onward, the FIT must be adjusted according to the last applicable central exchange rate between VND/$ issued by the State Bank of Vietnam on the previous year.

(ii) **Improved model PPA for rooftop solar power projects**. The new model PPA has been simplified for the sale of solar power from the rooftop solar generators to EVN and/or power purchasers and canceling the net metering structure which mixing of sale or purchase of power between the parties. Also, the sale of power from EVN and/or retail power companies to rooftop solar power generators shall be made under separate retail power purchase agreements and following the rules for supplying retail powers to end-user consumers.

(iii) **Other improvements**. The model PPA indicates clearly that the FIT will be applicable for 20 years, provides a detailed but simple formula to calculate the power generated and the price paid to the generators, and separates payment and invoice procedure for corporate entities from the one for individuals and households.

Upon the publication of the national Renewable Energy Development Strategy (Decision 2068/QD-TTg) in November 2015—while the scenarios in the Revised PDPVII were being analyzed—stakeholders wanted to explore renewable energy options. This led to the creation of two more scenarios in which the role of renewable energy in the future generation mix was enhanced. Both scenarios show a major expansion in renewable energy production and a decline in coal-fired power generation.

Internalization of Externalities

Planners in Viet Nam have a good understanding of the relevance of externalities in economic analysis, but the degree to which externalities are internalized as part of PDP preparation is extremely limited.

PDP Optimization

As in Thailand, planners in Viet Nam also use an old version of the Strategist planning software package to optimize their PDPs and although this package is slow and underpowered for contemporary requirements, the planners are skilled in finding work-arounds that, in part, redress the shortcomings of this package. In very recent times, the Institute of Energy in Viet Nam has started to use the Balmorel package, which is understood to be appreciably more powerful than their version of Strategist.

3.5 Cambodia

Demand Forecasting

PDPs in Cambodia are produced by foreign consultants, typically supported by the Japan International Cooperation Agency (JICA). The power utility Electricité du Cambodge (EDC) works alongside the foreign consultants but does not take a leading role.

ADB is supporting the Government of Cambodia in developing a 20-year PDP, which will include demand forecasts for the 2020–2040 period, generation planning scenarios, transmission and distribution scenarios, as well as an economic and environmental assessment of the options (e.g., on GHG emissions). An SEA is an integral part of the PDP preparation process. The technical work is being conducted by a consortium of international consultants (with national consultants as part of the team), under the coordination and supervision of a technical working group (TWG) with representatives of relevant ministries, including the Ministry of Mines and Energy (MME) and the Ministry of Economy and Finance. EDC, the national power utility, is also part of this TWG. The TWG is chaired by MME.

While the technical work is being conducted by international consultants, the PDP preparation has been accompanied by several technical training courses. In particular, training courses on (i) demand forecasting, (ii) energy efficiency, (iii) generation planning (including least-cost planning and dispatch simulations), (iv) renewable energy, (v) transmission planning (including power flow analysis and stability analysis), and (vi) SEA framework application.

At the same time, the institution that developed the 2015 PDP, Chugoku Electric Power Co., Inc., was engaged to formulate a PDP for 2020–2030, which included demand forecast, generation development, and a transmission development plan. As per the data we obtained, SEA was not part of the preparation process. This PDP was approved by a TWG in February 2020.

EDC has experience of working with OptGen and WASP IV, and also uses its own Microsoft Excel spreadsheet models. However, since these are unlikely to be suitable for IRP with SEA, Cambodia will need guidance on suitable software tools, and how to use them. ADB has supported PDP development where modeling has been carried out using the PROPHET model.

Analysis of Energy Efficiency Options

Energy efficiency is not considered in the PDP preparation or the demand forecasts (which were prepared separately). The concept of integrating DSM into least-cost planning is at the heart of IRP, and this approach has been applied to power since the 1970s, but not in Cambodia.

Analysis of Renewable Energy Options

Cambodian agencies seem to have the impression that intermittent renewable energy such as wind and solar is costly and likely to destabilize the grid. Mainly large hydropower plants are considered in the PDP. The mindset is gradually changing, however. ADB supported the Cambodia National Solar Park project, which was instrumental to this change in mindset. As part of this project, Cambodia is developing a 100 MW national solar park, and in 2019 it auctioned the first 60 MW of capacity which resulted in a record low procurement price for solar energy in the ASEAN region at $38.77 per MWh.[4]

Internalization of Externalities

Environmental costs do not appear to feature in past PDPs in Cambodia. The plan to develop five large hydropower projects and related transmission lines in the Cardamom Mountains, suggests that environmental and social costs were not taken into consideration during PDP planning.

ADB supported the PDP in which the SEA considers all key feasible technologies for Cambodia (coal, combined-cycle gas turbines [CCGTs], solar, wind, hydro, etc.), the potential locations of projects and their externalities.

As part of the SEA process, a scoring system has been devised to enable the pros and cons of technology options to be evaluated.

---

4 ADB. 2019. *ADB-Supported Solar Project in Cambodia Achieves Lowest-Ever Tariff in ASEAN.* News release. 5 September. https://www.adb.org/news/adb-supported-solar-project-cambodia-achieves-lowest-ever-tariff-asean.

PDP Optimization

Cambodia completed its PDP in 2015, which was prepared by international consultants under support from JICA.[5] This PDP fell short of an IRP in a few important aspects:

(i) Only large-scale conventional generation sources, mainly coal and large-scale hydropower, were included in the generation options.

(ii) Energy efficiency measures were not considered in the demand forecasts.

(iii) Renewable energy—other than large hydropower—was predetermined to be of marginal potential and consequently not included to any significant degree.[6]

(iv) The plan was prepared on a least-cost basis with only technical and financial data considered, i.e., neglecting externalities such as social and environmental costs.

(v) No attempt was made to identify any potential transactional (i.e., internal) social or environmental impacts and such issues were not included in the time planning or cost calculations.

(vi) Little or no integration with other Cambodia plans and strategies for sustainable development.

(vii) Consultation much beyond the line ministry (the Ministry of Mines and Energy) does not appear to have been undertaken.

Apart from the application of the models referenced above, with costs apparently in financial terms and excluding both internal and external social and environmental costs, little or no economic analysis appears to have been incorporated into Cambodia's Power Development Master Plan.

Regarding the ADB-supported PDP (2020–2040), the following was noted:

(i) In projecting demand growth, low, medium, and high scenarios were introduced. At the same time, exogenous impacts including energy efficiency, electric vehicles (EVs), and behind-the-meter (BTM) solar are also being considered.

(ii) Different renewable energy uptake levels will be considered, in the scope of three scenarios:
    (a) maximum level of renewable energy at the same levelized cost of energy (LCOE) of the business-as-usual (BAU) trajectory;

---

5 The Chugoku Electric Power Co., Inc. 2015. *Power Development Master Plan in Kingdom of Cambodia: Final Report*. Hiroshima, Japan.

6 The 6000 MW of candidate hydropower capacity considered in the master plan included just four projects smaller than 30 MW.

(b) maximum feasible renewable energy uptake; and
(c) maximum uptake of renewable energy (alongside other measures) consistent with Paris Agreement goals.

(iii) Options for increased power exchange and integration in a regional GMS system will be considered.

(iv) Energy storage (including battery energy storage systems [BESSs] and distributed storage) will be considered.

3.6 Myanmar

Demand Forecasting

From 2017 to 2019, JICA supported a capacity-building project in power development planning. During the first cycle of the JICA program in 2017, the PDP preparation in Myanmar was based on cooperation between JICA consultants and the MOEE working group members, where the JICA consultants were providing the key technical expertise. During the second cycle in 2018, the MOEE working group members developed an update of the National Electricity Master Plan 2014 by themselves with help from JICA experts.

The MOEE, Department of Electric Power Planning (DEPP), and JICA set up seven working groups for the preparation of the PDP, including a working group on demand forecast where JICA experts worked together with the MOEE working group members, helping them with the update of the demand forecast and the entire 2014 National Electricity Master Plan.

Generally, the demand forecast for Myanmar's PDP is based on econometric forecasting techniques (based on macroeconomic indicators such as the International Monetary Fund projection of GDP and population, elasticities, etc.)

Analysis of Energy Efficiency Options

The 2014 demand forecast in the PDP has not included adjustments for energy efficiency improvements. The ongoing PDP update carried out by MOEE considers three scenarios in the electricity demand forecast—high case, base case, and low case. The impact of DSM improvements has been included in the so-called Energy Policy Case through assumed reductions of the annual electricity demand estimates by 1%. These estimates have not been based on assessments of actual energy efficiency and DSM programs.

Analysis of Renewable Energy Options

A 10% target of the share of non-hydropower renewable energy has been set by the experience of other countries in Southeast Asia, without analysis of resource potentials and without renewable energy being part of the planning process as a possible supply technology. In the expansion plan optimization using WASP, the 10% renewable energy share limit is modeled as a negative load and/or demand, i.e., the overall demand is reduced by the portion of demand covered by non-hydropower renewable energy.

Internalization of Externalities

The internalization of externalities is not applied in Myanmar's PDP.

PDP Optimization

Some elements included in Myanmar's most recent PDP are consistent with an IRP approach:

(i) The merits of energy efficiency and DSM measures were recognized but apparently for future action and not integrated with the plan's demand forecast.

(ii) Diverse expansion scenarios were considered—albeit only three—and the long-run marginal cost of generation was determined for each.

(iii) GHG emissions were to be mitigated using ultra-supercritical coal, integrated coal gasification combined cycle, and CO_2 capture and storage technologies.

(iv) The potential detrimental environmental and social impacts of power development were recognized—albeit without monetizing the impacts—using an approach with some similarities to an SEA. To set right these concerns, the plan recommended that small and medium scale hydropower projects should be developed, together with solar power.

(v) An MCA approach was used to evaluate alternative scenarios and to assist with decision making in respect of environmental and social considerations.

However, renewable energy (other than large hydropower) was considered as suitable only for rural electrification purposes. As mentioned in subsection 3.6, a target of 10% of non-hydropower renewable energy capacity by 2030 was set, but it is not clear whether this was on- or off-grid.

The Myanmar PDP section on economic and financial analysis was undertaken solely in financial terms. As noted in subsection 3.6 at no point in the plan were there attempts to internalize externalities.

3.7 The Lao PDR

Demand Forecasting

Electricite Du Laos (EDL) prepares the power demand forecast with support from experts from Viet Nam's Ministry of Planning and Investment. IPPs in the Lao PDR submit annual generation plans to EDL.

The demand forecast focuses principally on residential demand and large loads (industrial and mining) and considers specific consumption. The forecasting takes account of development plans prepared by other ministries and departments. There is considerable uncertainty about some of the proposed major new loads.

Analysis of Energy Efficiency Options

There has been no consideration in the PDP process of energy efficiency goals and targets developed under separate programs by the Institute of Renewable Energy Promotion of the Ministry of Energy and Mines.

Analysis of Renewable Energy Options

There have been no considerations in the PDP process so far of renewable energy targets established under the Renewable Energy Development Strategy.

Internalization of Externalities

There have been no considerations of social and environmental issues in the PDPs so far.

PDP Optimization

In the Lao PDR, a new PDP is being prepared by the Ministry of Energy and Mines in 2020, aided by the World Bank. It is understood that the scope of this PDP is closer to the Optimal Power Sector Plan envisaged in the 2012 law, and represents an opportunity to rectify the limitations of past approaches to PDP development. This will be done by ensuring that the provisions of the 2012 law are followed and the PDP reflects overall national development approaches and fully integrates social and environmental impact issues into its preparation, with the SEA to be implemented as part of the PDP preparation providing an opportunity to ensure that this is the case. TA 9003 has been advised that the PDP under preparation in 2020 will address the shortcomings of earlier PDPs and will include energy efficiency and DSM considerations. The PDP is consistent with the Renewable Energy Development Plan. EDL—which prepares the PDP—and the Institute of Renewable Energy Promotion (under the Ministry of Energy and Mines)—which prepares Renewable Energy Development Plan—consistently share data and information.

APPENDIX 4

Integrated Resource Plan Modeling in the Greater Mekong Subregion Countries

This subsection reviews the individual GMS countries' experiences with IRP modeling, as gathered from the gap analysis under TA 9003.

4.1 The PRC

Current Situation

As outlined in Appendix 3 Section A3.2, the NEA planning institute—EPPEI—uses a planning software package developed by the Central Technology Institute of China that is suitable for the specifics of the PRC power sector. A key feature of the power sector in PRC is that while demand is concentrated in the east, the primary energy sources are concentrated in the west. An important challenge for planners' efforts to increase the share of non-fossil sources of energy in the power generation mix is that their cost remains more expensive than for conventional generation sources, plus the fact that conventional sources are required to maintain system stability and to satisfy baseload demand.

IRP modeling scenarios are based on consideration of GDP and population growth, along with higher and lower levels of the target of reducing the energy consumption per unit of GDP by 15% by 2020 relative to the 2015 level. Additional considerations have been given to expected norms of efficient coal consumption for generating a unit of power, emissions reduction targets, and the impact of new technologies.

Recommendations for Enhancement

As mentioned earlier, EPPEI uses a planning software package developed by the Central Technology Institute of China. The PRC authorities did not bring any shortcomings of this package to the attention of TA 9003; and, if there were any, it is presumed that the Central Technology Institute of China could modify the software to meet the evolving requirements of EPPEI. Meanwhile, it is recommended that NEA should use the opportunity of the RPTCC meetings held twice a year to share experiences with the other GMS countries on the effectiveness of expansion planning models.

4.2 Cambodia

Current Situation

Japanese consultants, supported by JICA, prepared Cambodia's most recent PDP in 2015. As with previous PDPs in the country, EDC worked alongside the foreign consultants but did not take a leading role. ADB is supporting the Government of Cambodia in developing a 20-year PDP, which will include demand forecasts for 2020–2040, generation planning scenarios, transmission and distribution scenarios, as well as an economic and environmental assessment of the options (e.g., on GHG emissions).

EDC has access to the OptGen software program for optimizing generation expansion—which was provided by JICA—and they have been trained in its use. OptGen has a mixed-integer linear programming (MILP) routine for optimization and has many of the key attributes needed for IRP preparation in Cambodia. They also use WASP IV and in-house Microsoft Excel spreadsheet models. OptGen is an excellent tool for expansion optimization, as discussed in subsection 6.5 of the main report. The utility of WASP IV to Cambodia is uncertain, however, since the package is not ideally suited to a hydrothermal system such as Cambodia's, where there are several hydropower projects and also several candidate hydropower projects. WASP was originally developed during 1970–1974 when the Tennessee Valley Authority was seeking to develop nuclear power stations. The WASP IV version is the most recent upgrade, but itself is more than 20 years old. An important constraint is that hydropower projects must be compounded together since the model can only represent two hydropower projects. ADB has supported PDP development by modeling that has been carried out using the PROPHET model.

Recommendations for Enhancement

The OptGen package is understood to have many of the attributes required to assist with IRP preparation in the GMS countries. EDC should continue to seek support to gain experience with the use of this package as an integrated element of advancement to independent preparation of Cambodia's PDPs. Separately, Cambodia should find channels—maybe through the RPTCC meetings—to monitor experience in other GMS countries with their models and build on their current experience with PROPHET.

4.3 The Lao PDR

Current Situation

Consultants supported by JICA prepared the most recent PDP for the Lao PDR in 2015. Although a 2012 Amendment to the Law on Electricity envisaged improvements to the PDP preparation process in the country—i.e., that it should reflect overall national development approaches and fully integrate social and environmental impact issues into its preparation, with an SEA to be implemented as part of the PDP preparation—the 2015 PDP did not take account of the relevant provisions. Similarly, although the country has policies in place on sustainable development, renewable energy, and EE&C, these policies were not meaningfully considered in the preparation of the 2015 PDP.

There was no modification of the demand forecasts used in the 2015 PDP preparation to reflect energy efficiency opportunities. Also, the consideration of social and environmental issues was restricted to screening against infringement of protected areas.

Large, export-oriented hydropower IPP projects and dedicated transmission line developments outweigh those for domestic consumption and are planned separately as of 2020. Consequently, the system is not integrated and despite the considerable investment in dedicated transmission lines, the national grid does not benefit from these and is generally insufficiently robust.

EDL does not have licensed software to optimize the generation expansion program and, in the past, it has generally used the software provided by consultants and IPP developers.

Recommendations for Enhancement

EDL acknowledges that they will need software to optimize the dispatch of a hydrothermal system, recognizing that coal and/or lignite-fired capacity is set to be added to the system.

The PDP under preparation in 2020 may guide EDL on the most suitable software to use for future IRPs in the Lao PDR. Nevertheless, the Lao PDR delegates to the RPTCC meetings should use every opportunity to discuss the relative merits of the packages in use in the GMS countries in 2020. Also, once a decision is made on software suited to the needs of the Lao PDR system, the support of the IFIs should be sought to develop capacity in EDL.

4.4 Myanmar

Current Situation

As noted in Appendix 3 Section A3.6, the most recent PDP of Myanmar included various elements consistent with an IRP approach:

(i) The merits of energy efficiency and DSM measures were recognized, but they were not integrated with the plan's demand forecast.

(ii) Three diverse expansion scenarios were considered, and the long-run marginal cost of generation was determined for each.

(iii) GHG emissions were to be mitigated using ultra-supercritical coal, integrated coal gasification combined cycle, and CO_2 capture and storage technologies.

(iv) The potential detrimental environmental and social impacts of power development were recognized—albeit without monetizing the impacts—using an approach with some similarities to an SEA. To address these concerns, the plan recommended that small- and medium-scale hydropower projects are developed, together with solar power.

(v) An MCA approach was used to evaluate alternative scenarios and to assist with decision making in respect of environmental and social considerations.

However, renewable energy (other than large hydropower) was considered as suitable only for rural electrification purposes. A target of 3,000 MW of non-hydropower renewable energy capacity by 2030 was set, but it is not clear whether this was on- or off-grid.

The plan's section on economic and financial analysis was undertaken solely in financial terms. At no point in the plan were there attempts to internalize externalities.

Modeling for IRP in Myanmar may prove challenging—despite the support of leading IFIs—due to the fragmentation of responsibilities for power planning, renewable energy and EE&C in the country, and the lack of an effective coordinating body.

Recommendations for Enhancement

Consultants working with MOEE on recent PDP preparation have used both GTMax and WASP IV, and capacity building in the use of these packages has been provided to MOEE staff. GTMax has a MILP routine for optimization and has many of the key attributes needed for IRP preparation in Myanmar. WASP IV, by itself, has limitations but may complement the use of GTMax to some extent. MOEE should continue to seek support—from JICA and other IFIs—to gain experience with the use of these packages, as an integrated element of advancement to independent preparation of Myanmar's PDPs.

Myanmar should take advantage of every opportunity—including the RPTCC meetings—to gain knowledge on experience with generation expansion planning models in the other GMS countries.

4.5 Thailand

Current Situation

Generation and transmission expansion modeling is undertaken by EGAT using the ABB Strategist model for generation optimization. EGAT also uses in-house spreadsheet-based software for short-term planning purposes. The EGAT version of

Strategist is around 12 years old and has never been updated by EGAT. Possibly as a consequence, long run-times for certain scenario modeling were experienced for the 2015 PDP, i.e., several days per run. The modeling of intermittent renewable energy in Strategist requires careful consideration and EGAT introduces it as a constraint in the model by assuming it to be must-run or must-take energy. This may require the demand profile to be modified. The modeling using Strategist does not appear to have included specific energy efficiency options in the optimization, the energy efficiency plan was developed to meet long-term targets, and the consequential reductions in demand were used as input data to the Strategist modeling exercise.

On the issue of internalizing economic externalities, EGAT advises that it is possible, within Strategist, to put CO_2 emissions as a constraint, i.e., in terms of metric tons of CO_2 per annum, rather than as a cost (\$/tCO_2e). Since the SEA process would ideally incorporate parameters such as pollution, land use, or deforestation into the PDP modeling, EGAT acknowledged that this may be a challenge for existing expansion planning software suites.

EGAT IRP modeling integrates the results of the development plans for both renewable energy and energy efficiency.

Recommendations for Enhancement

EGAT has advised TA 9003 that its Strategist software package has experienced limitations in preparing PDPs: specifically, long run times when optimizing the PDP. Updating the version of Strategist may rectify this shortcoming, but it may be better if EGAT were to invest in a more modern package—the Strategist developer, ABB, has developed a more flexible and powerful package, i.e., e - 7.

EGAT might usefully liaise with the Institute of Energy in Viet Nam on their experience with the Balmorel software package and, also, take advantage of the RPTCC meetings to explore experiences in other GMS countries with their software.

4.6 Viet Nam

Current Situation

IRP modeling for Viet Nam's PDPs is undertaken by the Institute of Energy—which uses Strategist and PDPAT II for this purpose. As with EGAT in Thailand, the Institute of Energy version of Strategist is around 12 years old and has never been updated. PDPAT II was provided under a donor-supported project some years previously. Strategist is not the most recent available and is understood to have struggled with the modeling for Revised PDP VII. Although optimization runs using Strategist can take extended periods, the results are not significantly different from those produced by a more current and powerful optimization model, as detailed in subsection 6.1 of the main report.

Modeling the Viet Nam system is challenging for several reasons: it has a complex power system with major demand centers at the extremes of a very long and narrow transmission network, and it has significant hydropower generation plants that have both seasonal inflow characteristics and multipurpose release constraints. National development policies also require energy efficiency and renewable energy opportunities to be maximized to meet CO_2 reduction targets and other sustainability goals.

Recommendations for Enhancement

TA 9003 has noted that the Institute of Energy Strategist software package—in its current form—is unsuited to the preparation of an IRP for Viet Nam. Had the institute subscribed to the updates to this package over the past 12 years, the situation may have been slightly different. However, ABB has itself developed the more flexible and powerful package e-7 that suggests progression away from Strategist is overdue. Under support from the Danish government, the institute has been provided with the Balmorel package as well as training in its use and application. Balmorel uses a MILP routine for the optimization, which appears to conform with current best practice in the industry. At the time of writing, MOIT and the Institute of Energy were preparing PDP VIII and can take a view on software progression after PDP VIII is concluded.

APPENDIX 5

Country-Specific Recommendations

This subsection considers the skills needed in each GMS country for it to independently undertake good practice IRPs with SEAs. It might be mentioned at this point that the PRC, Thailand, and Viet Nam have transferrable skills that could be provided to the other GMS countries. Nevertheless, it cannot be ruled out that even these countries have areas where capacity building would improve their performance.

There is a recent development that may have implications for each of the GMS countries. The RPTCC Working Group on Performance Standards and Grid Codes has drafted a regional grid code for the GMS countries, including a connection code. Some GMS countries may therefore require capacity-building support to adjust their current grid code and grid connection rules to the new regional grid code once it enters into force.

The subsection on Guiding the Transition—which is addressed for each country separately—provides insights and recommendations on how the GMS countries might transition to IRPs with SEAs.

5.1 The PRC

Human Capacity Building

Human capacity in the PRC is extremely high by international standards and it is not immediately apparent whether human capacity building is required for the advancement of IRP with SEA in the country. Given the differences between the PRC Planning EIA methodology and a more internationally recognized SEA approach, there is the potential for workshops and/or twinning activity to add value by giving the PRC institutions greater insight into international methods.

Institutional

Cost–benefit analysis in environmental impact assessments focuses on assessing costs and benefits related to emissions and solid waste (primarily from coal) and their abatement, along with any other cost and benefits that might be quantified in a specific project or program.

Some environmental costs and benefits are not easily quantifiable, such as those related to the environmental impact on biodiversity and human health. The costs and benefits are identified qualitatively in feasibility studies for individual projects and less readily in PEIAs.

While there are no specific requirements about quantifying environmental costs and benefits, the standard PEIA format includes a section requiring analysis of the "relationship between economic, social and environmental benefits; relationship between current benefits and long-term benefits." This requirement provides an incentive for quantifying the environmental and social costs and benefits in each plan to the best extent possible. There is scope to further strengthen the application of this approach through legislation and/or regulation.

The preparation of EIAs could be further improved in terms of (i) coordination between planning and environmental authorities, and (ii) streamlining the categorization of guidelines. The PRC authorities can carry out these improvements.

Methodology

The robustness of the environmental and social cost–benefit analysis—as well as the overall analysis in the PRC PEIAs and EIAs—could be extended to capture more comprehensively the additional impacts on biodiversity, coastal marine areas, human health, forestry, agriculture, etc., commensurately with the gradual enhancement of relevant analytical capacities and methodologies in these areas.

In the context of the ongoing under utilization (i.e., curtailment) of installed renewable energy generation capacity (primarily wind and solar) additional analysis may be useful for balancing the development of new intermittent renewable energy capacity with transmission planning and electricity demand forecasts.

While current DSM measures are focused on mitigating curtailments in wind and solar power supply in certain areas of the PRC, DSM measures could be further expanded to other areas of the power system to further alleviate peak loads and to optimize the pattern of electricity consumption, as needed. The relevant PRC entities—including the two grid companies and the generating companies—have the capacity for such an expansion of the scope of the DSM measures.

The possibility of expanding the use of liquefied petroleum gas and/or LNG for heating and cooking—instead of using electricity—may be further analyzed to enhance the impact of various energy efficiency measures on reducing electricity consumption. For example, in the PRC, 80,000 housing estates in Shenzhen, a major city in Guangdong Province, have been converted to LNG.

The RPTCC working group on performance standards and grid codes recently completed common operating rules for the transmission systems of the GMS countries, related also to cross-border lines.

Guiding the Transition

Engineers, planners, and economists in the PRC are highly skilled and more likely to be involved in transferring those skills to other developing countries than they are to be the recipients of capacity building.

The previous subsection observes that there is scope within the PRC agencies to further strengthen the application of social and environmental costs in their EIAs and PEIAs for power through legislation and/or regulation. The same subsection also notes that the preparation of EIAs could be further improved.

Subsection 5.1 suggests several areas where the PRC might modify the methodologies used for its PEIAs for power and its PDPs. For example, the scope of its PEIAs and EIAs could be expanded to capture the adverse impacts of power projects more fully. Analytical techniques are needed for balancing the development of new intermittent renewable energy capacity with transmission planning and electricity demand forecasts. The scope of EE&C and DSM measures could also be expanded.

The implementation of these suggestions would initially focus on any changes to legislation and regulations, followed by modifications to the methodologies.

5.2 Thailand

Human Capacity Building

Additional capacity needs to be developed in the agencies involved in the PDP to ensure that the new approach—PDP with a mandatory integrated SEA—can be implemented.

EGAT takes responsibility for PDP preparation in Thailand and does so without much consultation outside the utility. To prepare an IRP with an SEA would require EGAT to consider how to augment capability with the soft skills (i.e., social and environmental assessments) needed for an SEA.

EGAT does not currently capture the cost of externalities in its PDPs. GHG emissions are handled by capping CO_2 emissions in each year as a constraint—rather than by applying a cost to each tCO_2e arising from projects. TA 9003 considers that it should be possible to do both. Generally, EGAT is not equipped to quantify and monetize externalities and this is an area where capacity building is required. EGAT may require a small team of environmental economists to work on the IRP and the SEA, but they will need training once the team is established. EGAT undertakes little or no estimation of social and environmental mitigation costs, either.

The MONRE may have some of the required skills in environmental economics, which may be used to strengthen the capacity of EGAT in this respect. However, if

MONRE is to be charged with reviewing SEAs prepared by EGAT, training should come from independent sources.

Institutional

In 2020, Thailand is transitioning back to a parliamentary democracy, which may lead to institutional changes. Consultation on the PDP is undertaken in Thailand following standard government requirements. Subject to any constraints in the national guidelines on consultation, a more participatory consultation process would help to accelerate the evolution from a PDP to a good practice IRP with an SEA.

Although TA 9003 had previously been informed that an SEA and PDP reform process was ongoing—driven by strong government commitment and expected to include enhancements to the legal frameworks—the PDP approved in January 2019 did not include an SEA. An institutional structure to prepare, review, and approve SEAs for the PDP needs to be established.

There is no legal structure for PDP preparation; the government requests one when they consider one is needed, and EGAT prepares them over around 12 months. There is no separate budgetary provision for their preparation. A transition from the present PDP format to an IRP with SEA will require additional resources at EGAT, especially if they are to be updated more frequently than at present. The government should recognize—based on the experience from Viet Nam and Myanmar—that undertaking a meaningful SEA requires additional inputs in terms of time, finance, and skilled human resources.

Increasing the proportion of renewable energy in the plant mix will require investment from private developers. The following measures may assist in lowering barriers to private participation in renewable energy:

(i) ensuring more transparent and non-discriminatory connection procedures;

(ii) providing adequate public information for investors;

(iii) advancing electricity pricing reform (i.e., tariffs closer to cost-recovery level);

(iv) enhancing the visibility of future auctions; and

(v) enhancing consumers' awareness of the advantages of renewable energy solutions, along with ensuring good quality standards of service to strengthen consumers' engagement and stimulate demand for renewable energy service and subsequent increase in the share of renewable energy.

A good practice followed by EGAT for providing public information for investors consists of publishing a map of available capacity in each node of the transmission system for connecting new renewable energy.

The present grid code for Thailand does not include specific requirements for renewable energy, and augmentations will therefore be required if the proportion of intermittent renewable energy in the plant mix becomes significant. Other measures are also needed to remove the barriers for renewable energy to be connected to the grid.

Active involvement of the Ministry of Energy in multilateral bodies is desirable to foster regional cooperation and improve cross-border interconnection planning and operation in the GMS.

Institutional obstacles to the expansion of energy service companies in Thailand need to be removed, and measures taken to incentivize EE&C to a greater degree.

Under the energy conservation program launched in 1992, the Energy Conservation and Promotion Fund was established to provide financial support to introduce and promote new and renewable energy technologies. The capital for the fund was initially secured through the existing Oil Fund. Levies from petroleum producers and importers, power surcharges—as well as remittance rates from consumer petrol prices—ensure continuous capital inflow to the Fund.

The energy conservation program is meant to contribute to promoting energy conservation through awareness raising, as well as the adoption of energy-efficient technologies and promoting the development of RES.

Assistance with developing energy management processes, including International Organization for Standardization 50001, as well as improving the contractual aspects of the energy service company operations will help expand the possibilities for energy efficiency improvements.

Electricity tariffs in Thailand are understood to be set below cost-recovery levels. This may be part of the government's strategy. However, if EE&C is to be expanded in Thailand, tariffs will need to align more closely with the true economic cost, otherwise the market will remain distorted to the disadvantage of EE&C measures and incentives for EE&C will be ineffective.

Understanding the capability of rural areas to support the development of RES, particularly biomass-based RES, may require the mobilization of local resources beyond what has been used to prepare the AEDP in the past.

There have been numerous attempts to motivate and promote renewable energy in Thailand, considered the most developed market for renewable energy in the GMS. Thailand was the first country to implement a FIT for renewable energy in ASEAN. Before 2015, Thailand had an adder rate—which was payable to renewable energy producers as a premium to the prevailing wholesale price of electricity—and this was successful in promoting biogas small power producers (SPPs). The significant expansion of renewable energy is set out in the 2015 PDP, reflecting targets defined in the AEDP. This, in turn, reflects wider national development policies that see renewable energy as an integral part of Thailand's development future.

To meet the growing power demand, Thailand is expected to develop a significant amount of generation capacity—considering plant additions and retirements in line with the PDP of 2015. Solar photovoltaics in Thailand are expected to grow at a compound annual growth rate of 8.9% from 2018 to 2050 when the penetration of RES (including hydropower and biomass) in the generation mix is expected to reach almost 50%.

Thailand's power market operates in an enhanced single-buyer structure, where EGAT still dominates Thailand's power sector despite the introduction of IPPs, SPPs, and very small power producers. Enhanced refers to the participation of three classes of privately owned generators: IPPs, SPPs, and very SPPs. Power distribution in the Bangkok greater metropolitan area is carried out by the Metropolitan Electricity Authority and outside Bangkok by the Provincial Electricity Authority. Both are statutory enterprises under the Ministry of Energy.

The Division of Solar Energy Development is a unit under the ministry to promote the development of alternative energy. The division formulates the AEDP which aims at increasing the use of renewable energy, reaching 25% of Thailand's total energy consumption by 2036, the share of renewable generation to 20% (the AEDP was revised to include a 6 GW cumulative target for solar energy by 2036).

Methodology

When SEA is eventually applied to IRP preparation, a cohesive methodology for integrating the two needs to be developed.

EGAT uses a version of the Strategist software suite that has not been updated since it was procured around 12 years ago. EGAT has coped well with this software, even though each run can take several days to complete. ABB is understood to have introduced a more powerful software suite and EGAT should seriously consider upgrading since the computations required to undertake a good practice IRP in Thailand will inevitably become more demanding.

Methodologies and related software tools are needed to ensure the inclusion of specific EE&C options when optimizing IRPs, capturing life cycle costs, and impacts on a BAU demand forecast.

Guiding the Transition

Thailand is different from the other GMS countries in that it does many aspects of PDP preparation skillfully and in an organized manner, while at the same time being markedly deficient in other aspects.

EGAT and the other institutions involved with PDP preparation require capacity building in the aspects of an IRP with an SEA that are neglected—as noted in subsection 5.2. The integration of an SEA with the PDP is perhaps the most significant area where new skills are required. Support from international specialists may be required for this. Consultation mechanisms need to be upgraded and, although skills may exist in Thailand, EGAT may require training in this area. Consideration of externalities is a key area where EGAT needs to augment its skills, resorting to external support with capacity building.

In terms of institutional aspects, subsection 5.2 noted that Thailand is transitioning back to a parliamentary democracy—which may lead to institutional changes that impinge on power and environmental safeguarding. Although the concept of an SEA is not new to Thailand, an institutional structure to prepare, review, and approve an SEA for the PDP needs to be established. IRPs with an SEA will require additional financial resourcing. Subsection 5.2 listed several measures aimed at lowering the barriers to private participation in renewable energy. Also, Thailand's grid code and other measures are needed to remove the barriers for renewable energy to be connected to the grid. Thailand will also need to implement the common operational rules once these emerge from the RPTCC. Various measures to promote EE&C have been identified, not least to align tariffs more closely with cost-recovery levels.

Following the themes raised in the previous paragraph, the agencies in Thailand will need to introduce models and methodologies to implement the various changes. These are elaborated in subsection 5.2.

5.3 Viet Nam

Human Capacity Building

The Institute of Energy has SEA specialists who have worked alongside the team of international experts engaged to support the preparation of the SEAs for hydropower aspects of PDP VI and the original and the revised PDP VII. The institute will prepare the SEA for PDP in 2019. It should be noted that Viet Nam is moving toward annual updates to the PDP, and it is presumed that each update will require an SEA. If the institute is to undertake the bulk of these SEAs on its own, then—bearing in mind the comments in the three earlier SEAs on the available time and budgetary constraints of those SEAs—the institute will likely need additional human resources to equal or improve the rigor the SEAs in respect of aspects such as consultations and internalizing externalities.

The capacity of provinces to plan for renewable energy investments needs to be strengthened, which includes a need for provincial plans to be able to integrate SEAs.

Greater capacity for preparing various SEA aspects needs to be developed to ensure full integration of enhanced SEAs in the PDP. Where technically possible, this can be achieved through the internalization into the economic analysis of power supply options of the major environmental and social costs relating to such things as (i) GHG emissions, (ii) air and water pollution, (iii) loss of amenity, and (iv) impact on endangered species.

The above costs have been traditionally treated as externalities in Viet Nam, and not considered in the economic analysis of different power options.

Analysts at the Institute of Energy need to develop skills and contemporary databases to arrive at cost calculations for the main externalities in the PDP that are grounded in both international norms and local circumstances. Significant progress has been made in this regard in the SEA of the Revised PDP VII, but there are areas where further improvements need to be made.

National policies and the outcomes of the SEA point toward a greater emphasis on renewable energy and energy efficiency. This is challenging because experience, information, and models for planning renewable energy and energy efficiency effectively need to be significantly strengthened, given their very different characteristics from traditional power generation options used in the past.

Institutional

National goals and targets in fields such as climate change mitigation, energy efficiency, and renewable energy must be fully reflected in the PDP objectives and outcomes, and effectively harmonized in all relevant documents and programs.

Methodology

Access to suitable tools needs to be ensured for the Institute of Energy to formulate an IRP with an SEA approach that can ensure an optimal mix of renewable energy, energy efficiency measures, and international transmission interconnections. As with EGAT in Thailand, the institute also uses an old version of the Strategist software suite. The institute has also coped well with the limitations of this software, but it should seriously consider upgrading to a more powerful package.

The PDP framework and methodologies need to be adjusted to ensure that full social and environmental costs as well as non-traditional options such as DSM and renewable energy are fully integrated into the PDP preparation, toward achieving a good practice IRP approach to power planning.

There is a need for a methodological framework and targeted capacity building for a PDP that more fully integrates an SEA into an IRP and that reflects Vietnamese legislation. Government procedures should be also produced.

There is a need to develop appropriate normative cost figures for renewable energy options such as wind and solar that reflect the Vietnamese resource potentials and conditions. There is also a need to ensure that the models used in the preparation of the PDP are ones that are effective in considering renewable energy and energy efficiency options.

In the coming years, Viet Nam will have to implement significant changes in its connection, planning, and operation processes to facilitate further RES integration. The new requirements in the Vietnamese distribution code can be implemented more easily and should be therefore adopted with priority:

(i) Frequency ranges within which the generating unit shall be capable of operating to align the requirements for small solar units with all other units.

(ii) Active power controllability: even the smallest units shall be equipped with a logic interface (input port) to cease active power output following an instruction being received at the input port.

(iii) Alignment of the Vietnamese requirement for the capability to exchange realtime information with the European requirement (>1 MW).

(iv) Set transparent and equitable rules for defining the financial contribution of the owner of the generating facilities to the extension works required for its connection.

There is a need to develop appropriate normative cost figures for the costs and likely effectiveness of energy efficiency programs and national targets for reducing future demand growth.

A minimum objective for the updated PDP should be developing new cross-border interconnections to maintain the interconnection ratio of Viet Nam constant (around 3%).

In the case of a subregional integrated electricity market being implemented in the GMS, a more ambitious target could be adopted (typically from 5% to 10%). Viet Nam has no explicit limit at present.

A methodology should be developed and agreed with the involved neighboring countries for estimating the economic benefits of new cross-border interconnection for the overall region and individually for each country.

A common view on operational security should be developed beyond the national level to enable taking advantage of cross-border interconnections.

Specific objectives for integrating the power and reserve markets in the subregion should be also set.

Guiding the Transition

Viet Nam is possibly the most advanced country in the world—and not just the GMS—in terms of already having the legal and regulatory frameworks, institutional structures, and skills for applying an exceptionally good standard of IRP with SEA.

Subsection 5.3 highlights the more significant areas where there is potential for Viet Nam to enhance its human capacity to undertake a good standard of an IRP with an SEA. In brief, the key institutions—Institute of Energy and MONRE—need to strengthen capacity in preparing and reviewing SEAs that are more rigorous than they are at present, especially in respect of issues such as monetizing externalities. Although the institute and MONRE already have good skills in SEAs, it is doubtful that capacity building through organic development will be sufficiently rapid, especially with the proposed move toward annual PDPs. Instead, support from the IFIs will be needed. The institute already has most of the technical skills to transition its PDPs to good standard IRPs. New models will be required, however, and staff will require training with using these.

Viet Nam arguably has the necessary frameworks and institutions needed for an IRP with an SEA. However, subsection 5.3 suggests clearer harmonization of national targets in the PDP, i.e., across development policy, green growth, EE&C, renewable energy, etc.

Subsection 5.3 notes a few areas where Viet Nam ought to consider upgrading the methodologies applied to PDP and SEA preparation. New models for system optimization, greater attention to the monetization of externalities, a greater focus on EE&C, renewable energy, and transboundary interconnections are some of the principal areas where the institute should seriously consider improvements to enhance the rigor of an IRP with SEA.

In chronological terms, capacity building is the most urgent requirement, not least because of the move to annual PDPs. This capacity building needs to recognize any significant changes in the methodologies and models to eventually be applied for an IRP with an SEA.

5.4 **Cambodia**

Human Capacity Building

Capacity building for PDP preparation and approval—in the corresponding agencies—needs to commence at a very elementary level before working up to more detailed methodologies. Care also must be taken to ensure that the approaches and methods introduced are of practical use considering the likely levels of capacities in these organizations.

Capacity building must also ensure that the PDP approach developed is strongly rooted in the wider framework of national development policies that are increasingly emphasizing a sustainable development and green growth approach.

Cambodia will need to include capacity building on the fundamentals of internalizing external social and environmental costs into the economic analysis of PDPs.

Capacity building in Cambodia needs to start with the fundamentals of an IRP in the PDP, coupled with increasing awareness of what an SEA entails, especially when integrated with an IRP approach to PDP preparation. This development of awareness and capacities must be implemented in an incremental, practical manner with new ideas and approaches explained in ways that can be seen to be relevant and useful for PDP preparation.

Building on the experience of Viet Nam and Myanmar, consideration should be given to Cambodia's first SEA being a retrospective SEA examining all or part of the 2015 PDP. This would provide an instructive lesson without disrupting or delaying the process of PDP preparation. This retrospective SEA ought to be directed to consider the proposed development of hydropower schemes and related transmission lines in the Cardamom Mountains, given the potentially significant social and environmental cumulative impacts, which were not considered in the 2015 PDP.

Support to EDC may be needed to ensure adherence to the operating rules related to cross-border transmission lines, which have been drafted by the RPTCC once they enter into force.

Institutional

If Cambodia is to transition towards independent capability in PDP preparation, this goal needs to be formulated in a formal policy or initiative.

A clearer policy on the scope and character of a PDP needs to set by the highest policy-setting level of government, to ensure that the characteristics of the PDP are in line with national approaches to sustainable development. More effective interministerial coordination is needed in this regard.

The timing and scope of PDPs, and the institutions involved in preparation, review, and approval, need to be reflected in legislation and regulations.

Methodology

If Cambodia is to transition toward independent preparation of its PDP, it will need suitable software and staff who are well trained in its use.

If not already done, a comprehensive assessment can be undertaken of the potential from all forms of renewable energy that can be theoretically developed in Cambodia (such as large and small hydropower, wind, solar, and biomass). A comparative study can then be also undertaken to identify potential lower cost renewable energy supply alternatives to current imports and thermal options. If this analysis provides a basis for considering an increase in the share of renewable energy (hydropower and non-hydropower) in a sustainable way, additional consideration may be given to ensuring the enabling frameworks are suited for such an increase, through improvements in the grid code, strengthening the transmission network, and automated control of the generation output of the power plants.

The potential reduction of electricity consumption because of planned energy efficiency and DSM programs needs to be reflected in the electricity demand forecast in the PDP, and therefore processes need to be modified to accommodate this. Also, the costs of the energy efficiency and DSM programs leading to the reduction of electricity consumption need to be reflected in the total costs of the PDP, to ensure an adequate overall assessment of the costs and benefits related to the PDP.

Guiding the Transition

Cambodia—in common with the Lao PDR and Myanmar—is well behind countries such as Viet Nam in terms of readiness to adopt an IRP with an SEA. Support from the IFIs will be required and there may be economies of scale from applying common training programs and other measures.

Numerous capacity-building measures are recommended for Cambodia in subsection 5.4. These suggest a progression from elementary measures to more detailed methodologies. Monitoring and evaluation (M&E) of the usefulness of the measures should also be undertaken. Key capacity-building areas are likely to include fundamentals of IRPs and SEAs and their integration, internalization of externalities, and operating rules for cross-border transmission lines.

A fundamental institutional issue is that Cambodia does not have a stated goal to transition toward independent capability in PDP preparation. If this is a national goal, then it ought to be formalized in a national policy or initiative. Other institutional issues—as noted in subsection 5.4—include clearer policies on the scope and character of a PDP that are aligned with national policies on sustainable development. This will require more effective interministerial coordination.

Models and methodologies for undertaking an IRP with an SEA will be needed, and not necessarily those used by the consultants recruited to prepare past PDPs. Key examples of this include approaches to identifying and assessing renewable energy and EE&C opportunities that have been neglected in the past.

On sequencing, consideration should be given to Cambodia's first SEA being a retrospective SEA examining all or part of the 2015 PDP. Before this is contemplated, however, extensive capacity building and institutional development will be needed. Capacity building and methodology development for an IRP with an SEA would extend over several years.

5.5 Myanmar

Human Capacity Building

The current lack of capacity for PDP and an IRP with an SEA preparation can be gradually overcome with support from the ongoing JICA capacity-building project for MOEE, followed by expanding similar donor-supported programs to other ministries and agencies involved in the PDP process. A training-of-trainers approach should also be considered.

There is a strong interest within the MOEE and the private sector in learning about Viet Nam's experience with integrating SEAs in Viet Nam's power planning process. Extending the twinning arrangements beyond TA 9003 should be considered. Outreach to the PRC and Thailand is also advised, to learn from their experience on SEAs.

Extensive capacity building is required in SEA preparation and review, across all sectors and the various agencies involved. The capacity building would include identification, quantification, and monetization of both internal and external social and environmental impacts, along with various other relevant topics.

JICA is providing critical assistance to MOEE staff with developing SEA guidelines. Given the important role of MONREC in reviewing SEAs and the current lack of capacity for such reviews, it will be useful to consider including relevant MONREC staff to practice developing SEA guidelines separately in another capacity-building program. Representatives of other ministries that are likely to develop programs requiring SEAs may be also included in such a separate program.

Capacity for stakeholder and community consultations need to be enhanced at MOEE, for both IRP and SEA purposes.

Further capacity-building assistance is also likely to be needed in (i) implementing the EE&C Law and achieving the established targets, including the assessment of EE&C potential, preparation, monitoring, and evaluation of the impact of energy efficiency and conservation programs; and (ii) adequately incorporating energy efficiency impacts on both supply and demand sides in the PDP process, in consideration of the impact on electricity demand and overall costs of the PDP.

Since the Ministry of Information has not been involved in PDP preparation to date, capacity building may be required to strengthen the relevant skills and understanding of ministry staff to enable them to contribute to PDP preparation. Otherwise, capacity building on EE&C will be needed within MOEE.

Institutional

An institutional structure to prepare, review, and approve SEAs for the PDP needs to be established. This should ensure provisions for adequate consideration of renewable energy, energy efficiency, and interconnections are key elements of an IRP approach to the power planning process. To the same end, the 2014 Electricity Law ought to be amended to provide greater direction on the scope, responsibilities for review preparation, and approval of IRPs.

TA 9003 did not notice any senior government official prepared to advocate for implementing an IRP with an SEA in Myanmar in the near term. If serious progress is to be made with implementing an IRP with an SEA, a champion for this objective is urgently required. Ultimately, the Environmental Protection Law of 2012 would need an amendment to make SEAs mandatory.

If Myanmar is to transition toward independent preparation of its PDP, this goal needs to be formulated in a formal policy or initiative.

Recent PDPs in Myanmar more closely resemble basic least-cost PDPs than they do IRPs. This may, in part, be due to the terms of reference for these PDPs simply recycling those from previous exercises, without challenging the aims and objectives of a PDP. MOEE could be more proactive in preparing terms of reference for technical assistance through donors for PDP preparation so that in future they move toward good practice in IRPs with SEAs.

Myanmar is already experiencing serious project delays due to opposition and legal challenges from NGOs and affected groups. To solve this issue, stakeholder consultation mechanisms need to be overhauled. A formal consultation process for PDPs—and eventually SEAs—needs to be established in Myanmar through legislation.

Discrepancies between the various projections and demand forecasts in recent years could be overcome by improving within the relevant local institutions the quality of the input data. Mechanisms to monitor and evaluate the accuracy of forecasts from previous PDPs should be instituted.

Given the institutional responsibility of MONREC for environmental protection, it will be useful to ensure a clear definition of this responsibility in relevant regulations and legislation.

Good collaboration between MOEE and MONREC is needed to coordinate relevant methodologies and to review procedures and agree on SEA characteristics and boundaries.

Ensuring adequate coordination between the ministries and agencies involved in renewable energy work—through a higher authority interministerial coordinating body, or through a dedicated unit at the MOEE, absorbing renewable energy experts from the ministries of education and agriculture—is essential for enhancing the PDP process.

Developing an enabling policy and the legal and regulatory environment for renewable energy—such as including standardized PPAs, grid access rules, and quality standards—is an important factor for improving access to financing and achieving specific renewable energy targets established within the PDP process.

A national connection code—in line with the GMS requirements—is needed to enable the integration of large shares of renewable generation capacity (e.g., solar and wind) to the grid.

Designing competitive and transparent selection rules for developers of power generation in Myanmar is needed, coupled with ensuring a transparent and uniform application of connection rules and charges to all investors to facilitate the investors' interest in developing new renewable energy sources of generation and their subsequent integration to the grid. This will then facilitate the PDP implementation.

The assignment of responsibilities relating to power and PDP preparation needs to be clearly outlined in the new EE&C law. EE&C expertise largely resides within the MOI, at present, and MOI is not consulted by MOEE for PDP preparation purposes.

Adoption of common operational rules relating to interconnections between the GMS countries—under preparation by the RPTCC in 2020—is needed to facilitate cross-border interconnections.

MOEE needs to invest more resources in high-voltage lines. Financial resourcing needs to consider higher retail tariffs or leveraging the inward investment in export projects. This can contribute toward maximizing the benefits from projects for exporting power to neighboring countries such as Bangladesh, India, the Lao PDR, the PRC, and Thailand.

Methodology

TA 9003 does not understand the rationale for disbanding the National Energy Management Committee (NEMC)—as there has never been a greater need in Myanmar for coordination across the energy sector, which is highly fragmented at present. Coordination of the activities of various ministries involved in PDP and/or IRP work needs to be restored. A high-level body, with suitable level of authority—like the NEMC—is needed to oversee PDP and IRP work and ensure proper consideration of inputs from other agencies, dealing with renewable energy and energy efficiency, which have been left out of the PDP process so far. These are (i) the Ministry of Education (Department of Research and Innovation for Renewable Energy); (ii) the Ministry of Agriculture, Livestock and Irrigation (dealing with rural electrification through renewable energy); and (iii) the Ministry of Industry (dealing with energy efficiency). If Myanmar is to transition toward independent preparation of its PDP, it will need suitable software and staff that are well trained in its use.

The definition of renewable energy targets needs to be based on analysis of resource potential, as well as consideration of renewable energy technologies as supply options within a thorough power planning analysis, also including a comparative analysis of costs and benefits of other power supply alternatives. Within this context, current targets for non-hydropower renewable energy, including small hydropower, could be further reassessed.

It will be useful to harmonize the values and the composition of renewable energy targets among the relevant ministries toward improving the overall PDP process. Renewable energy targets need to indicate whether they relate to specific types of non-hydropower renewable energy or whether they include all types of renewable energy in the country, including hydropower (large or small). This will then facilitate the development of relevant renewable energy technologies to reach such targets (non-hydropower, small hydropower, large hydropower).

The demand forecast approach needs to indicate whether demand includes both demand growth through grid extensions and off-grid solutions as well as their respective shares in overall demand. This would then facilitate the optimization of power supply options to adequately meet grid-based and off-grid demand.

Constraints to using land for renewable energy development, resulting in loss of productive agricultural land, could be overcome by considering, where possible, floating solar panels and dual use of land (agriculture and renewable energy), depending on the irradiation needs of the specific crop and adjusting the orientation, angle, and distance between panels. The application of Japan’s experience in this regard may be useful.

System operation will need to be improved to cope with RES intermittency once the penetration of solar reaches a certain threshold. Advanced operational tools such as automatic generation control and intermittent generation forecasting service will also need to be introduced.

Incorporating cost–benefit analysis in the transmission planning process will contribute significantly to sustainably developing transmission infrastructure.

A more holistic approach is needed for the development of the transmission network and cross-border interconnections. Such an approach also needs to be translated into policy frameworks.

Guiding the Transition

In addition to having limited experience in the key issues relating to an IRP with an SEA, Myanmar is hampered by a highly fragmented power sector and by the disbandment of the organization established to coordinate the various agencies and ministries. Rectifying this issue would be an important priority in the process of an IRP with an SEA.

Myanmar's MOEE is already receiving good support from an ongoing capacity-building program provided by JICA, as noted in subsection 5.5, and other related agencies and ministries are also receiving support from the IFIs. A training-of-trainers approach is something that might be considered to address the scale of capacity deficits. Outreach to the PRC, Thailand, and Viet Nam is suggested for twinning in key areas related to IRPs with SEAs. Extensive capacity building is required in SEA preparation and review, including the identification, quantification, and monetization of both internal and external social and environmental impacts, although it is noted that JICA is assisting the MOEE with developing SEA guidelines. Capacity for stakeholder and community consultations needs to be enhanced at MOEE, for both IRP and SEA purposes. EE&C has been neglected at MOEE in the past, and this shortcoming needs to be rectified.

Numerous institutional changes are required in Myanmar if an IRP with an SEA is to be implemented, as noted in subsection 5.5. An institutional structure to prepare and approve SEAs for the PDP needs to be established, with provisions for consideration of renewable energy, energy efficiency, and interconnections. Also, the 2014 Electricity Law should be amended to require and define IRPs. Similarly, the Environmental Protection Law of 2012 would need an amendment to make SEAs mandatory. If Myanmar is to transition toward independent preparation of its PDP, this goal needs to be formulated in a formal policy or initiative. Until they are prepared independently, however, MOEE could be more proactive in preparing terms of reference for technical assistance through donors for PDP preparation, so that in future they move toward good practice in an IRP with an SEA.

Stakeholder consultation mechanisms need to be overhauled. An M&E mechanism is required to evaluate demand outcomes relative to the forecasts in past PDPs. Collaboration between MOEE and MONREC is needed to coordinate methodologies and to review procedures and agree on SEA characteristics and boundaries. An enabling policy, legal, and regulatory environment for renewable energy is urgently required. Various measures are required to enable private renewable energy developers to be selected and to integrated with the grid.

Models and methodologies for IRP preparation, and particularly for identifying and assessing EE&C and renewable energy options are needed in Myanmar, as remarked in subsection 5.5. System operation approaches will need to be improved to cope with RES intermittency, once the penetration of solar energy reaches a certain threshold. The transmission planning process needs to incorporate economic analysis methodologies, and a more holistic approach is needed for the development of the transmission network and cross-border interconnections, supported by policy frameworks.

5.6 The Lao PDR

Human Capacity Building

There is a need to increase awareness and capacity of the relevant agencies concerning IRPs and IRP with SEAs.

The Department of Energy Policy and Planning (DEPP) should recognize that including an SEA in the PDP will soon be a legal requirement, so building capacity and modifying the PDP process to include an SEA is essential.

Implementation of the new Electricity Law would require considerable capacity building. Since there are numerous donors involved in power sector reform in the Lao PDR, DEPP considers that it will be necessary to ensure coordination of the capacity building between ADB, World Bank, JICA, and US Agency for International Development (USAID) programs. For example, the assistance given to the Ministry of Energy and Mines by JICA with the development of a new PDP—which will include an SEA—needs to be coordinated with the World Bank's assistance to MONRE for preparing SEA guidelines.

Domestic expertise in off-grid and on-grid electrification needs to be developed, along with technical centers to provide recommendations on the types and sizes of solar panels for specific buildings.

Capacity needs to be developed in preparing energy efficiency action plans in the relevant key areas, such as buildings, industry, and transportation.

Institutional

The institutional structure for an IRP with an SEA approach suitable for the Lao PDR conditions needs to be developed.

There is a need to coordinate the envisaged provincial and sector pilot SEAs with the overall national SEA guidelines under preparation.

Responsibilities and mandates for different parts of the SEA preparation and approval process need to be defined.

The legal and institutional structure for developing export-oriented hydropower projects and the legal and institutional structure for domestic electricity supply need to be harmonized to the extent possible to facilitate a comprehensive coverage of all actors in the power sector in the PDP process.

The planning responsibility under the proposed Electricity Law needs to be further elaborated and clarified to the relevant agencies through a secondary legislative act (i.e., regulation, ordinance, or decree) to facilitate the coordination between the relevant agencies, and thus the overall PDP process.

The existing Renewable Energy Development Strategy needs to be

(i) enhanced beyond the current focus on biofuels for transportation to other renewable sources supporting power generation; and

(ii) included in, and harmonized with, the targets and priorities in key national development programs and strategies, including those of the JICA-supported PDP under preparation in 2020.

Fiscal incentives (e.g., subsidies, taxes, and duty exemptions), together with the establishment of an independent regulatory authority for the energy sector, will be needed to facilitate renewable energy development and integration of non-hydropower renewable energy options in the PDP process. Import duty exemptions are needed to facilitate the imports of solar panels, and EDL acknowledges this.

Institutional responsibilities need to be defined more clearly and reflected in relevant programmatic and legal documents.

Methodology

The new PDP exercise supported by JICA represents an opportunity to correct the deficiencies observed by TA 9003 in previous PDPs through the following actions:

(i) incorporating large hydropower plans oriented to exports in the PDP process, together with off-grid electrification, energy efficiency and DSM considerations, and non-hydropower renewable energy generation (e.g., wind, solar, biomass);

(ii) harmonizing the goals and targets of the separate thematic policies and strategies for renewable energy and energy efficiency; and

(iii) optimizing the sequencing of hydropower plants, primarily developed by investors, instead of the current ad hoc first-come, first-served approach to developing these power plants.

All agencies involved in the PDP preparation process need to understand the implications of the emerging necessity to include social and environmental analysis in the plan and to build planning procedures and capacities to respond to this need.

EDL needs access to suitable programming software that will optimize the generation expansion and dispatch in a hydrothermal power system that also includes variable renewable energy.

The principles of sustainable hydropower development adopted by the government in 2015 need to be applied to the new PDP under preparation with support from JICA in 2020.

Due to the surplus of cheaper hydropower in the Lao PDR during the wet season (May to November), and the reluctance of the neighboring countries to import intermittent wind and solar power from the country, it may be useful to:

(i) Focus the analysis on the sustainability of a potential increase in the share of the non- hydropower renewable energy (e.g., wind, solar, biomass) during the dry season (November to May) to only meet possible domestic deficits in supply in comparison with alternative imports or domestic supply from other sources of power generation.

(ii) Assess whether, under a scenario in which during the dry season there may be a domestic deficit of supply that can be met sustainably through increased supply from intermittent non-hydropower renewable energy sources, the following are needed to accommodate an increased share of intermittent renewable energy in the power system: (i) grid code connection rules; (ii) mechanisms of related connection charges; (iii) level of automating the control on generation output; and (iv) the status of the related transmission network to make adjustments and upgrades in each of these areas, as needed.

The potential reduction of electricity consumption resulting from energy efficiency and DSM programs needs to be reflected in the electricity demand forecast for the PDP.

The costs of the energy efficiency and DSM programs leading to the reduction of electricity consumption need to be reflected in the total costs of the PDP to ensure an adequate overall assessment of the costs and benefits related to the PDP.

The PDP should consider exports, while recognizing that the volume of exports is a significant proportion of total output.

The operating rules related to cross-border lines, which are under preparation by the RPTCC, will need to be adhered to once they enter into force.

The reliability, capacity, and interconnectivity between the northern, central, and southern zones of the grid need to be augmented to ensure appropriate movements of imported power to key load centers in the country.

The reserve margin requirements need to be upgraded under the requirements of the power system's operations.

Guiding the Transition

There is a general need to increase awareness and capacity in respect of IRPs and SEAs, as suggested in subsection 5.6. DEPP needs to recognize the impending legal requirement for SEAs, and start building capacity and methodologies, accordingly. Implementation of the new Electricity Law will require considerable capacity building, which will require coordination between the various IFIs supporting the key sectors. Domestic expertise in off-grid and on-grid electrification needs to be developed. Planning responsibilities under the proposed Electricity Law needs to be further elaborated and clarified to the relevant agencies through a secondary legislative act to facilitate the coordination between the agencies, and thus the overall PDP process.

An institutional structure for an IRP with an SEA needs to be developed, together with other institutional modifications, as detailed in subsection 5.6. There is a need to coordinate the envisaged provincial and sector pilot SEAs with the overall national SEA guidelines under preparation, and responsibilities and mandates for different parts of the SEA preparation and approval process need to be defined. Electricity exports are of great strategic importance to the Lao PDR, and consequently, the legal and institutional structure for developing export-oriented hydropower projects and the legal and institutional structure for domestic electricity supply need to be harmonized.

Subsection 5.6 noted that the existing Renewable Energy Development Strategy needs to be expanded and harmonized with the targets and priorities in key national development programs and strategies. Fiscal incentives, together with the establishment of an independent regulatory authority, will be needed to facilitate renewable energy development and integration of non-hydropower renewable energy options in the PDP process.

Transforming Power Development Planning in the Greater Mekong Subregion

A Strategic and Integrated Approach

This publication provides guidance on how governments and utilities in the Greater Mekong Subregion (GMS) can develop sustainable power development plans based on current international best practices. It outlines how the integration of strategic environmental assessments to an integrated resource planning approach can enable power development plans to explore or better manage renewable energy sources efficiently. It also discusses the benefits and key principles of this approach, with technical guidelines for each of the six GMS countries and tools aimed for use by practitioners in Asia and beyond.

About the Asian Development Bank

ADB is committed to achieving a prosperous, inclusive, resilient, and sustainable Asia and the Pacific, while sustaining its efforts to eradicate extreme poverty. Established in 1966, it is owned by 68 members —49 from the region. Its main instruments for helping its developing member countries are policy dialogue, loans, equity investments, guarantees, grants, and technical assistance.

ASIAN DEVELOPMENT BANK
6 ADB Avenue, Mandaluyong City
1550 Metro Manila, Philippines
www.adb.org